AIR QUALITY

Testimony of Jacquelyn Leyva

SUMMARY OF CONCLUSIONS

Energy Commission staff (staff) concludes that with the adoption of the attached conditions of certification the proposed Hidden Hills Solar Electric Generating System (HHSEGS) project would comply with all applicable laws, ordinances, regulations, and standards (LORS) and would not result in any significant air quality-related California Environmental Quality Act (CEQA) impacts. With implementation of the conditions of certification referred to herein, the project would comply with LORS and mitigate otherwise adverse impacts for purposes of CEQA. Without adequate fugitive dust mitigation, the project could cause potential localized exceedances of the PM10 National Ambient Air Quality Standards (NAAQS) during construction and operation. This impact would be less than significant with adoption of the proposed construction and operation fugitive dust mitigation measures.

Staff concludes that the project would meet the minor source provisions of the federal New Source Review (NSR) program and thus would not require Prevention of Significant Deterioration (PSD) review or Nonattainment New Source Review.

The HHSEGS project would emit substantially fewer greenhouse gas (GHG)[1] emissions per megawatt-hour produced than fossil-fueled generation resources in California. The project is not subject to the requirements of SB 1368 (Greenhouse Gases Emission Performance Standard; Cal. Code Reg., tit. 20, § 2900 et. seq.) and the Emission Performance Standard; however it would nevertheless meet the Emission Performance Standard.

INTRODUCTION

This analysis evaluates the expected air quality impacts from the emission of criteria air pollutants from both the construction and operation of the HHSEGS project. Criteria air pollutants are air contaminants for which the state and/or federal governments have established an ambient air quality standard to protect public health.

The criteria pollutants analyzed are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), and particulate matter (PM). Toxic air pollutant emissions impacts are analyzed in the **Public Health** section of this FSA. Two subsets of particulate matter are inhalable particulate matter (less than 10 microns in diameter, or PM10) and fine particulate matter (less than 2.5 microns in diameter, or PM2.5). Nitrogen oxides (NOx, consisting primarily of nitric oxide [NO] and NO_2) and volatile organic compound (VOC) emissions readily react in the atmosphere to form ozone and, to a lesser extent, particulate matter. Sulfur oxides (SOx) readily react in the atmosphere to form particulate matter and are major contributors to acid rain. Global

[1] Greenhouse gas emissions are not criteria pollutants; they affect global climate change. In that context, staff evaluates the GHG emissions from the proposed project (Appendix Air-1), presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.-

climate change and greenhouse gas (GHG) emissions from the project are discussed in **Appendix Air-1** in the context of cumulative impacts.

In carrying out this analysis, the California Energy Commission (Energy Commission) staff evaluated the following major points:

- whether the HHSEGS project is likely to conform with applicable federal, state, and Great Basin Unified Air Pollution Control District (District) air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- whether the HHSEGS project is likely to cause new violations of ambient air quality standards or contribute substantially to existing violations of those standards (Title 20, California Code of Regulations, section 1743);
- whether mitigation measures proposed for the project are adequate to lessen potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

The federal, state, and local laws and policies applicable to the control of criteria pollutant emissions and mitigation of air quality impacts for the HHSEGS are summarized in **Air Quality Table 1**. Staff's analysis examines the project's compliance with these requirements and summarizes the applicable LORS.

Air Quality Table 1
Laws, Ordinances, Regulations, and Standards

Applicable LORS	Description
Federal	
40 Code of Federal Regulations (CFR) Part 52	Nonattainment New Source Review (NSR) requires a permit and requires Best Available Control Technology (BACT) and Offsets. Permitting and enforcement is delegated to GBUAPCD with EPA oversight. Prevention of Significant Deterioration (PSD) requires major sources or major modifications to major sources to obtain permits for attainment pollutants. The HHSEGS project is a new source has and is a rule-listed emission source, thus the PSD trigger levels are 100 tons per year for NOx, VOC, SO_2, PM2.5 and CO. This project's proposed emissions are below NSR and PSD applicability thresholds.

Applicable LORS	Description
40 CFR Part 60	**New Source Performance Standards (NSPS), Subpart Dc Standards of Performance for Electricity Steam Generation Units.** Establishes emission standards and monitoring/recordkeeping requirements for units with less than 30 MMBtu/hr heat input. **Subpart Db Standards of Performance for Electricity Steam Generation Units.** Establishes emission standards and monitoring/recordkeeping requirements for units with greater than 100 MMBtu/hr heat input. **Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.** Establishes emission standards for compressions ignition internal combustion engines, including emergency firewater pump engines.
State	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with Air Resource Board (ARB) approved Clean Air Plans.
HSC Section 41700	Restricts emissions that would cause nuisance or injury.
TItle17, California Code of Regulations (CCR),section 93115	**Airborne Toxics Control Measure for Stationary Compression Ignition Engines.** Limits the types of fuels allowed, established maximum emission rates, establishes recordkeeping requirements on stationary compression ignition engines, including emergency firewater pump engines.
Title13 ,CCR, section 2423	**Exhaust Emission Standards and Test Procedures: Heavy-Duty Off-Road Diesel Cycle Engines.** Limits the tier levels of emissions from heavy-duty off-road diesel cycle engines, including emergency backup generators and emergency firewater pump engines.
Assembly Bill 32: Global Warming Solutions Act of 2006 and related GHG reduction regulations	Reduce emissions of GHGs; operator must purchase and surrender GHG allowances, as required.
Local (Great Basin Unified Air Pollution Control District, GBUAPCD)	
Rule 200, 209, 210, 216 Permits Required	Requires a Permit to Construct before construction of an emission source occurs. Prohibits operation of any equipment that emits or controls air pollutant without first obtaining a permit to operate.
Rules 400, 401, and 402 Nuisance, Visible Emissions, Fugitive Dust	Limits the visible, nuisance, and fugitive dust emissions. Applicable to both the construction and operation phases of the project.
Rule 403 – Breakdown	Defines breakdown conditions and describes procedures to be followed by the owner/operator and by the APCO in the event of occurrence of breakdown conditions.

Applicable LORS	Description
Rule 404-A Particulate Matter - Concentration	Limits the particulate matter concentration from stationary source exhausts.
Regulation IX Standard of Performance for New Stationary Source	Incorporates the Federal NSPS (40 CFR 60) rules by reference.
Rule 217– Federal Operating Permits	Requires new or modified major facility or facilities that trigger NSPS, Acid Rain or other federal air quality programs to obtain a Title V federal operating permit.
Regulation III – Permit Fees	Requires facilities subject to this regulation to pay permit fees.
Rule 416 Sulfur Compounds and Nitrogen Oxides	Limits NOx and SO_2 emissions from combustion sources.

SETTING

CLIMATE AND METEOROLOGY

The project would be located in southeastern Inyo County, on the edge of California's eastern border with Nevada at approximately 2,600 feet above sea level. Relatively high daytime temperatures, extremely low relative humidity, large and rapid diurnal temperature changes, occasional high winds, and sand, dust, and thunderstorms characterize the high desert climate. Seasonally, the precipitation totals in the area range from 0.84 inches in February to 0.09 inches in June. The average precipitation in the project area is about 4.7 inches per year, half of which falls from December through March.

The most recent meteorological (weather) data, collected and maintained by the National Weather Service Cooperative Network located in Pahrump, on SR 160 in Nye County, Nevada is located approximately 8 miles "straight line" distance from the project site. The measured wind data are graphically represented by quarterly wind roses, provided in the AFC Figures 5.1-1 thru 5.1-5 (HHSEGS 2011a). Note that the standard convention is for the wind direction to head into the center of the plot. These wind roses show that for most of the year, prevailing winds are from the south through southeast, at an average wind speed of 2.1 meters per second. Mixing heights in the area, which represent the altitudes where different air masses mix together, are estimated to be on average 230 feet (70 meters) above ground in the morning to as high as 5,250 feet (1,600 meters) above ground level in the afternoon. Applicant and staff used supplemental cloud cover data from Henderson Airport in Nevada (located 48 miles east of the proposed site) and upper air data from Elko, NV (located 334 miles north of the proposed site).

The proposed project site is located within California at the California-Nevada border. It is near and generally upwind from Nevada's Clark and Nye Counties. Clark County's Department of Air Quality and Environmental Management, and the Nevada Division of Environmental Protection, Department of Air Quality Management, Bureau of Air Pollution Control ("Nevada DEP") provide air quality management for these two counties, respectively.

Sensitive Receptors

The local population is proximate to the project site, and includes many sensitive subgroups that may be at greater risk from exposure to emitted pollutants. These sensitive subgroups include the very young, the elderly, and those with existing illnesses. In addition, the location of the population in the area surrounding a project site may have a large bearing on health risk. The nearest residence to any power block equipment is approximately 3,500 feet south of the Solar Plant 2 power block and about 950 feet south of the project's southern boundary.

There is also a nearby project called the St. Therese Mission. It is a commercial facility under construction, which is located approximately 0.5 mile southeast of the HHSEGS site. This facility will be treated as a sensitive receptor because it will include a chapel, a garden, a restaurant, a visitor's center that will include a children's playground, and a residential unit. This facility is located within the modeling area for air quality. Impacts are assumed at this site and elsewhere in the modeling domain. For more detailed information on sensitive receptors, please see the **Public Health** section of this **FSA**.

EXISTING AMBIENT AIR QUALITY

The Federal Clean Air Act and the California Clean Air Act both require the establishment of standards for ambient concentrations of air pollutants, called ambient air quality standards (AAQS), set at levels to protect public health and welfare. The state AAQS, established by the California Air Resources Board (ARB), are typically lower (more protective) than the federal AAQS, which are established by the United States Environmental Protection Agency (U.S. EPA). The state and federal ambient air quality standards are listed in **Air Quality Table 2**. As indicated in **Air Quality Table 2**, the averaging times for the various air quality standards, the times over which they are measured, range from one-hour to annual averages. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 or $\mu g/m^3$, respectively).

In general, an area is designated attainment of an ambient air quality standard if the concentration of a particular air contaminant does not exceed the respective standard. Likewise, an area is designated non-attainment for an air contaminant if that contaminant standard is exceeded. Where not enough ambient air quality data are available to support designation as either attainment or non-attainment, the area is designated as unclassified. An unclassified area is normally treated the same as an attainment area for regulatory purposes. An area could be in attainment for one air contaminant while non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same air contaminant.

HHSEGS is located in the Great Basin Valleys Air Basin (GBVAB) and within the Great Basin Unified Air Pollution Control District (GBUAPCD). This area is designated as moderate nonattainment for the state ozone standard, nonattainment for the state PM10 standard, unclassified for federal ozone standard, and attainment or unclassified for the state and federal CO, NO_2, SO_2, and PM2.5 standards. **Air Quality Table 3** summarizes the area's attainment status for various applicable state and federal standards.

Air Quality Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.072 ppm (147 μg/m^3)	0.070 ppm (137 μg/m^3)
	1 Hour	—	0.09 ppm (180 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual	0.053 ppm (100 μg/m^3)	0.03 ppm (57 μg/m^3)
	1 Hour	100 ppb [b] (188 μg/m^3)	0.18 ppm (339 μg/m^3)
Sulfur Dioxide (SO_2)	Annual	0.030 ppm (80 μg/m^3)	—
	24 Hour	0.14 ppm (365 μg/m^3)	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1300 μg/m^3)	—
	1 Hour	75 ppb [c] (196 μg/m^3)	0.25 ppm (655 μg/m^3)
Particulate Matter (PM10)	Annual	—	20 μg/m^3
	24 Hour	150 μg/m^3	50 μg/m^3
Fine Particulate Matter (PM2.5)	Annual	15 μg/m^3	12 μg/m^3
	24 Hour	35 μg/m^3 [a]	—
Sulfates (SO_4)	24 Hour	—	25 μg/m^3
Lead	30 Day Average	—	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.01 ppm (26 μg/m^3)
Visibility Reducing Particulates	8 Hour	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.

a To attain this standard, the 3-year average of the 98th percentile of the daily concentrations must not exceed 35 μg/m3.
b To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average must not exceed 100 ppb.
c To attain this standard, the 3-year average of the 99th percentiles of the daily maximum 1-hour average must not exceed 75 ppb.
ppm= parts per million
Source: ARB 2012a

Ambient air quality monitoring data for ozone, PM10, PM2.5, CO, NO_2, and SO_2, compared to most restrictive applicable standards for the years between 2006 through 2011 (the last year that the complete annual data is currently available) at the most representative monitoring stations for each pollutant are shown in **Air Quality Table 4.** All ozone, PM10, and PM2.5 (up through 2011) data shown are from the Jean, Nevada, monitoring station located approximately 34 miles southeast of the project site. All CO data are from the Barstow, CA monitoring station located approximately 97 miles southwest of the project site. All SOx and NOx data are from the Trona, CA monitoring station located approximately 82 miles west southwest of the project site. Besides the

Jean monitoring station, which provides reasonably near ozone and particulate monitoring data, available monitoring stations for CO, NOx or SOx either are located just under a hundred miles away from the site, or in the case of Las Vegas, are otherwise not representative due to their urban location. Therefore, staff chose the GBVAB monitoring locations located in Barstow and Trona because they best represent the air quality conditions at the site. Staff expects that the background ambient concentrations for both of these pollutants to be relatively low at the project site due to its remote location. However, due to the relatively large distances from the proposed site, there is a reduced overall confidence in the representativeness of data from these monitoring stations.

Air Quality Table 3
Federal and State Attainment Status GBUAPCD [a]

Pollutant	Attainment Status [b]	
	Federal	State
Ozone	Unclassifiable/Attainment	Nonattainment
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Attainment	Nonattainment
PM2.5	Attainment	Attainment

Source: ARB 2011b, U.S. EPA 2011b.
a. Attainment status for the site area only, not the entire air basin. b. Attainment = Attainment or Unclassifiable.

Air Quality Table 4
Criteria Pollutant Summary Maximum Ambient Concentrations (ppm or µg/m^3)

Pollutant	Monitoring Station Location	Averaging Period	Units	2006	2007	2008	2009	2010	2011	Limiting AAQS
Ozone	Jean, NV	1 hour	ppm	0.092	0.092	0.087	0.082	0.082	.085	0.09
Ozone	Jean, NV	8 hours	ppm	0.083	0.088	0.078	0.079	0.076	.078	0.07
PM10 [a]	Jean, NV	24 hours	µg/m	62	60	96	81.3	49	79	50
PM10 [a, b]	Jean, NV	Annual	µg/m	12.1	12.7	14	12.4	8.5	*	20
PM2.5[c]	Jean, NV	24 hours	µg/m	9	9	13	11	10	12.6	35
PM2.5	Jean, NV	Annual	µg/m	3.52	4.0	4.9	4.0	3.5	*	12
CO	Barstow,	1 hour	ppm	3.5	1.4	1.4	1.2	1.3	4.4	20
CO	Barstow,	8 hours	ppm	1.19	0.7	1.23	0.089	0.089	1.35	9.0
NO_2	Trona, CA	1 hour	ppm	0.050	0.055	0.062	0.049	0.052	0.049	0.18
NO_2	Trona, CA	1 hour (98th	ppm	.042	.046	.043	.039	.043	0.043	.100
NO_2	Trona, CA	Annual	ppm	0.005	0.004	0.004	0.004	0.005	*	0.03
SO_2	Trona, CA	1 hour	ppm	0.033	0.014	0.036	0.011	*	0.001	0.25
SO_2	Trona, CA	24 hours	ppm	0.004	0.005	0.005	0.003	0.003	0.006	0.04
SO_2	Trona, CA	Annual	ppm	0.000	0.000	0.000	0.001	0.001	0.001	0.03

Source: ARB 2012, U.S. EPA 2012 Notes: * insufficient data available to determine the value.
a. Exceptional PM concentration events, such as those caused by windstorms are excluded in the data presented.
b. Annual average data is federal data and may not exactly represent California annual average.
c. The U.S. EPA database used for retrieval of the PM2.5 data did not allow direct determination of the calculated 98th percentile, which is the basis of the standard, so the closest proxy (third highest values) are presented.

Ozone

The area is considered "unclassified/attainment" for the federal 8-hour ozone standard and nonattainment for the state 8-hour ozone standard. The ambient data shown in **Air Quality Table 3** indicates that 8-hour concentrations near the site (Jean, Nevada) exceed the recently revised federal 8-hour ozone standard (0.075 ppm). However, the values shown are peak values that correspond to the state standard. The federal standard is the fourth highest 8-hour concentration in a year averaged over three years.

In a letter dated October 12, 2011, the California Air Resources Board proposed to U.S. EPA that the southern portion of Inyo County be designated attainment for the new federal 8-hour ozone standard (ARB 2011c) due to a design value which was measured during 2008 to 2010 at a fourth highest value equal to 0.072 ppm (averaged over the 3-year period) compared to the federal standard of 0.075 ppm. In April 2012 the U.S. EPA classified Inyo County as "unclassifiable/attainment" for the federal 8-hour ozone standard.[2]

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted nitrogen oxides (NOx) and hydrocarbons (volatile organic compounds [VOC]), which are called ozone precursors. These can transform to ozone in the presence of sunlight. The maximum 1-hour ozone concentrations monitored near the site in Jean, Nevada, have been relatively stable over the past ten years and are just over California's 1-hour standard for most years from 2006 to 2011. The maximum 8-hour ozone concentrations also have been relatively stable over the past years and are somewhat closer to their standard than the 1-hour ozone levels.

Staff notes that in the area of the project site at the far southeastern end of the GBVAB, there is the potential for ozone and ozone precursor transport from the Las Vegas area. The main geographical locations of the ozone precursor emissions for ozone levels observed in this region are primarily from pollutant transport from distant urban areas.

Nitrogen Dioxide

The entire air basin is classified attainment of the state 1-hour and federal short-term and annual nitrogen dioxide (NO_2) standards. The NO_2 levels monitored in Jean, Nevada, are no more than 35 percent of the most stringent California NO_2 ambient air quality standard. Most of the NOx typically emitted from combustion sources is in the form of nitric oxide (NO), while the balance is NO_2. NO is oxidized in the atmosphere to form NO_2, but some level of photochemical activity is needed for this conversion. The highest concentrations of NO_2 typically occur during the fall. The winter atmospheric conditions can trap NO emissions near the ground but lacking substantial photochemical activity (sun light), the oxidation rate of NO to NO_2 and NO_2 levels remain relatively low. In the summer, the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions disperse pollutants, preventing the accumulation of NO_2 at levels that might approach the 1-hour federal ambient air quality standard.

[2] http://www.epa.gov/airquality/ozonepollution/designations/2008standards/final/region9f.htm

Carbon Monoxide

The area is classified attainment of the state and federal 1-hour and 8-hour carbon monoxide (CO) standards. The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level. These conditions occur frequently in the wintertime late in the afternoon, persist during the night and may extend one or two hours after sunrise.

Particulate Matter (PM10)

The area is nonattainment for the state PM10 standard and attainment/unclassified for the federal standard. PM10 can be emitted directly as fugitive dust or combustion particulates, or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx and VOC from combustion sources, and ammonia (NH_3) from human and animal wastes or combustion NOx control equipment can, given the right meteorological conditions, form particulate matter known as nitrates (NO_3), sulfates (SO_4), and organic compounds. These pollutants are secondary particulates because they are not directly emitted but are formed through complex chemical reactions between directly emitted pollutants in the atmosphere.

Fine Particulate Matter (PM2.5)

Fine particulate matter, or PM2.5 (particulate matter less than 2.5 microns in diameter), is derived either mainly from the combustion of materials, or from precursor gases (SOx, NOx, and VOC) through complex reactions in the atmosphere. PM2.5 consists mostly of sulfates, nitrates, ammonium, elemental carbon, and a small portion of organic and inorganic compounds. A small percentage of PM2.5 emissions come from fugitive dust sources and motor vehicles combustion sources from the construction vehicles.

The Great Basin Valleys Air Basin in southeastern Inyo County where the proposed project site is located is classified as attainment or unclassified for both the state and the federal PM2.5 air quality standards, but as noted previously the area is not in attainment of the state PM10 standard. This divergence indicates that the ambient PM10 levels are most likely due to localized fugitive dust sources, such as vehicles travel on unpaved roads, agricultural operations, or wind-blown dust.

Sulfur Dioxide

The entire air basin is attainment for the state and federal SO_2 standards.
Sulfur dioxide is typically emitted from the combustion of fuels containing sulfur. Sources of SO_2 emissions within the GBVAB come from a wide variety of fuels: gaseous, liquid and solid; however, the total SO_2 emissions within the eastern GBVAB are limited due to the limited number of major stationary sources and California's and U.S. EPA's substantial reduction in motor vehicle fuel sulfur content. The project area's SO_2 concentrations are well below the state and federal ambient air quality standards.

Nitrates and Sulfates

PM nitrate (mainly ammonium nitrate) forms in the atmosphere from the reaction of NOx and ammonia. NOx from combustion sources is mainly in the form of nitric oxide (NO). NO converts to NO_2 primarily by reacting with ozone in the ambient air and sunlight. The formed NO_2 can convert back to NO, which sustains the ozone formation reactions. NO_2 can also form organic nitrates, or can be reduced to nitric acid by available hydroxyl radicals in the ambient air. Nitric acid reacts with ammonia in ambient air to form ammonium nitrate. Ammonium nitrate, in its particulate form, can remain suspended in the ambient air and/or be transported long distances downwind as PM2.5. Ammonium nitrate, under certain conditions of heat and humidity, breaks down to NOx and starts a new ozone cycle.

PM sulfate (mainly ammonium sulfate) forms in the atmosphere from the oxidation of SO_2 and subsequent neutralization by ammonia in the atmosphere. This oxidation of SO_2 depends on many factors, which include the availability of sulfur, hydroxyl, hydroperoxy and methylperoxy radicals, and atmospheric humidity. Given the low SO_2 and humidity levels in the site vicinity, PM sulfate levels would be low.

Summary

In summary, staff recommends the background ambient air concentrations in **Air Quality Table 5** for use in the modeling and impacts analysis. The recommended background concentrations are the maximum criteria pollutant concentrations from the past three years of available data collected at the monitoring stations staff selected as the most representative of the proposed project area.

Air Quality Table 5
Staff Recommended Background Concentrations ($\mu g/m^3$)

Pollutant	Averaging Time	Recommended Background	Limiting Standard	Percent of Standard
NO_2	1 hour	117	339	35%
	1 hour Federal	80.8	188	43%
	Annual	7.5	57	13%
PM10	24 hour	**96**	**50**	**192%**
	Annual	14	20	70%
PM2.5	24 hour	13	35	37%
	Annual	4.9	12	41%
CO	1 hour	1,750	23,000	8%
	8 hour	1,333	10,000	13%
SO_2	1 hour	93.6	655	14%
	24 hour	13.1	105	12%
	Annual	2.7	80	3%

Source: AFC Table 5.1-34 (HHSEGS 2011a); updated with ARB 2012.
Note that an exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.

Where possible, staff prefers that the recommended background concentrations come from nearby monitoring stations with similar land use characteristics. For this project, the monitoring station located in Jean, NV (ozone, PM10, and PM2.5 [up to 2011]) is located reasonably close to the project site and should be representative of the project site. The Barstow (CO) monitoring station is in a more populated area, and should be conservative compared to the project site. The Trona (NO_2 and SO_2) monitoring station, while located in a more remote area, has two very large nearby emission sources of SOx (Searles Valley Minerals and Ace Cogeneration Company) so this monitoring station location should provide representative or conservative SO_2 background concentrations for the project site.

The background 24-hour concentrations for PM10 are above the most restrictive existing ambient air quality standards, while the background concentrations for the other pollutants and averaging times are all below the most restrictive existing ambient air quality standards.

In accordance with applicable EPA modeling protocols, the pollutant modeling analysis includes the pollutants listed above in **Air Quality Table 5**.

PROJECT DESCRIPTION

The proposed HHSEGS would comprise two solar fields and a common area. The applicant has identified the northern solar plant as Solar Plant 1 and the southern plant as Solar Plant 2. Each solar plant would generate 270 megawatts (MW) gross (250 MW net), for a total net output of 500 MW. Each would have a central tower surrounded by distributed field of heliostat (mirror) arrays. The heliostats focus solar energy on the power tower receivers located at the top of the tower. HHSEGS Solar Plants 1 and HHSEGS Solar Plant 2, would occupy approximately 1,483 acres (or 2.3 square miles) and 1,510 acres (2.4 square miles) respectively. Both solar plants would share a common administration building, an operation and maintenance building, and a substation and would cover approximately 103 acres. The HHSEGS total project footprint amounts to approximately 3,097 acres (approximately 4.84 square miles). Another 180 acres would be needed during the construction period for lay down and staging activities. The temporary construction lay down area in addition to the entire HHSEGS site would total 3,277 acres.

Each plant would have five emitting sources, consisting of two natural-gas-fired boilers, two diesel fuel-fired emergency engines, and a wet surface air cooler. Additionally, the common area would contain diesel fuel-fired emergency equipment consisting of a small emergency generator and a fire pump. Two types of boilers would be used at each power block. Each boiler would be equipped with low-NOx burners and flue gas recirculation (FGR) for NOx control; CO would be controlled using good combustion practices; and particulate and VOC emissions would be minimized through the use of natural gas as the fuel. Specifications for the new boilers are summarized in the project operation section of this FSA.

Each plant would use one 249 million British Thermal Units per hour (MMBtu/hr) natural-gas-fired auxiliary boiler to facilitate daily start up by preheating the solar boiler and steam turbine generator piping before sufficient solar energy is available. This would enhance project efficiency by allowing solar flux to maximize output more quickly than if solar heating alone were used to heat the entire system. During cloudy days or in case of an emergency shutdown, these boilers would also keep the system hot to facilitate plant restart.

Additionally, one small (15 MMBtu/hr) natural-gas-fired boiler, called a nighttime preservation boiler, would be used at each plant to provide steam to keep the steam turbine generators and boiler pump gland systems under vacuum overnight and during other shutdown periods when solar heat is not available. Using these small boilers would be more efficient than allowing these systems to cool and then using the larger startup boilers to reestablish the vacuums in the morning.

On an annual basis, heat input from natural gas would be limited to less than 10 percent of the heat input from the sun. To save water in the site's desert environment, each solar plant would use a dry air-cooled condenser for steam condensing. A partial dry-cooling system (wet surface air cooler –WSAC) would provide auxiliary equipment cooling. Groundwater would be drawn daily from three wells located onsite; one at each power block and a third at the administration complex. Groundwater would be treated in an onsite treatment system for use as boiler make-up water and to wash the heliostats.

The HHSEGS would interconnect to the Valley Electric Association (VEA) system[3]. The interconnection would require an approximately 10-mile long generation tie line (gen tie line) from the HHSEGS to the proposed Crazy Eyes Tap Substation[4], where the project would interconnect to the VEA electric grid. The gen tie line would originate at the HHSEGS's onsite switchyard, cross the state line avoiding the mesquite vegetation to the south and continue east for approximately 1.5 miles until reaching Tecopa Road. At Tecopa Road, the route would head northeast paralleling Tecopa Road until it reaches the Crazy Eyes Tap Substation, which would be located immediately east of the Tecopa Road/SR 160 intersection. The Crazy Eyes Tap Substation would interconnect to the existing VEA Pahrump Bob Tap 230 kV line. (CH2 2012q)

A 12-inch diameter natural gas pipeline would be required for the HHSEGS project. Kern River Gas Transmission Company (KRGT) proposes to construct the pipeline from the HHSEGS meter station, to be located in the HHSEGS Common Area, extending 32.4 miles to KRGT's existing mainline system just north of Goodsprings in Clark County, Nevada. The HHSEGS meter station, including pig receiver facilities, would be approximately 300 feet by 300 feet and would be surrounded by a 6-foot tall chain link fence topped with three strands of barbed wire (approximately 7 feet high total). The meter station would be shaded by a canopy to cover the meter runs and associated instrumentation and valves. A data acquisition and control (DAC) building would be located within the meter station. Data acquisition, control, uninterrupted power supply (UPS), and communication equipment would be installed inside the DAC building. Yard lights would be installed on the DAC building and meter building exterior. In addition, the light fixtures would be shielded or hooded and directed downward (CH2 2012q).

The transmission and natural gas pipeline alignments would be located primarily in Nevada on federal land managed by the U.S. Bureau of Land Management (BLM), except for small segments of the transmission line (both options) in the vicinity of the Eldorado Substation located within the city limits of Boulder City, Nevada, which is located south of Las Vegas (see **Project Description Figure 3**). This assessment is limited to include only the portion of the transmission line system and natural gas pipeline linears to be located in California. Environmental aspects of the parts of these

[3] In January 2013, VEA will become a participating transmission owner (PTO) and will turn operational control of its facilities over to the California Independent System Operator (CAISO).

[4] In the HHSEGS Application for Certification, this substation was referred to as the Tap Substation.

linears located in Nevada would be assessed by the U.S. Bureau of Land Management (BLM).

Following completion of project licensing and close of financing, HHSEGS would be constructed in approximately 29 months with the following schedule:

- Begin construction: Second quarter 2013
- Startup and testing: Second quarter 2015 for Solar Plant 1; third quarter 2015 for Solar Plant 2
- Commercial operations: third quarter 2015 for Solar Plant 1; fourth quarter 2015 for Solar Plant 2

Project steam cycle cooling for each solar plant would use an air-cooled condenser (ACC) or dry cooling for each of the plants. Water consumption would be, therefore, minimal—mainly to provide water for washing heliostats and for boiler make up. Process wastewater would be treated onsite. Domestic wastewater would be disposed of in a septic tank and an onsite leach field. Therefore, no industrial wastewater or sewer pipeline would be constructed.

The project would include other operating emission sources for operation and maintenance of the facility. Each plant would include a diesel-fired 200-horsepower (hp) fire pump engine (2 total at the HHSEGS project site) along with a 200-hp fire pump in the common area. One 3,633-hp emergency generator engine would be located at HHSEGS Solar Plant 1 and another at HHSEGS Solar Plant 2, along with one smaller 398-horsepower emergency generator engine at the common area (3 total at the HHSEGS project site). Additionally, the applicant has proposed that the facility would have engines for the mirror washing equipment that would be EPA-certified, non-road or on-road engines[5] to power mirror-washing trailers and dedicated pickup trucks for personnel transport within the plants. These would create both tailpipe and fugitive dust emissions during operation.

PROJECT CONSTRUCTION

Construction of the common area facilities would occur concurrently with the construction of the first solar plant.

There would be an average daily workforce, during the peak 12-month period of approximately 1,749[6] construction craft people, supervisory, support, and construction management personnel onsite. The peak construction site workforce of 2,293 is expected to occur in month 19 (see Updated Workforce Analysis, CH2 2012jj, Section 1.0 page 1-1).

Generally, construction activities would occur from 5:00 a.m. to 3:30 p.m. with a swing shift during heliostat assembly from 6:00 p.m. to 4:30 a.m. Additional hours may be necessary to make up schedule deficiencies, or to complete critical construction activities (e.g., tower construction, foundation pouring, or working around time-critical

[5] Data Response, Set 2A in response to Staff's Data Request Set 2A filed on January 9, 2012

[6] See CH2M 2012jj "Updated Workforce Analysis" Section 2.0 Air Quality Table AQ-1.

shutdowns and constraints). During some construction periods and during the startup phase of the project, some activities would continue 24 hours per day, 7 days per week.

Air Quality TABLE 6
Project Schedule Major Milestones

Activity	Date
Solar Plant 1 and Common Area	
Fencing and tortoise clearance	Second Quarter 2013
Begin construction	Second Quarter 2013
Startup and commissioning	Second Quarter 2015
Commercial operation	Third Quarter 2015
Solar Plant 2	
Fencing and tortoise clearance	Second Quarter 2013
Begin construction	Third Quarter 2013
Startup and commissioning	Third Quarter 2015
Commercial operation	Fourth Quarter 2015

Air Quality Table 7 presents the applicant's estimate of direct onsite and offsite (delivery and employee vehicle) construction emissions for NOx, VOC, SOx, CO, PM10 and PM2.5.

Air Quality Table 7
HHSEGS Construction Emissions

	Daily Emissions (lbs/day) [a, b]					
Solar Facility Construction	NOx	SOx	CO	VOC	PM10	PM2.5
Maximum Daily Onsite Emissions	384.4	0.65	192.3	29.3	190.8	37.7
Maximum Daily Offsite Emissions[C]	313.0	0.6	436.6	58.5	13.4	10.3
Maximum Daily Emissions	697.4	1.25	628.9	87.8	204.2	48.0
	Annual Emissions (tons/year) [a]					
Maximum Annual Onsite Emissions	34.2	0.06	17.5	2.62	12.6	2.7
Maximum Annual Offsite Emissions[d]	11.6	0.01	24.2	3.0	0.6	0.4
Maximum Annual Emissions	45.8	0.07	41.7	5.6	13.2	3.1

Source: AFC (HHSEGS 2011a), supplemental data submitted April 2, 2012 (CH2 2012p) and updated workforce analysis submitted Oct. 2012 (CH2 2012jj)

Notes:

a. Onsite emissions include fugitive dust, construction equipment, and concrete batch plant
b. Max daily onsite emissions occur during month 8 and 9, with the maximum daily offsite emissions occur during Month 19. Values in the table are now representative of the maximum daily emission, which occur during month 8.
c. Maximum Daily Offsite Emissions are from month 8 and 9 of the updated Construction Traffic Assumptions document submitted on October 2, 2012, Air Quality Section 2.2 Table AQ-3.
d. Maximum Daily Annual Offsite Emissions can be found in the updated Construction Traffic Assumptions document submitted on October 2, 2012, Air Quality Section 2.2 Table AQ-4.

On October 1, 2012, staff received applicant document titled, “Updated Workforce Analysis (Air Quality, Socioeconomics, Traffic and Transportation, and Worker Safety & Fire Protection). Staff has reviewed the information, noted the changes to construction emissions, and reflected the new values are in **Air Quality Table 7** above.

These emission estimates appear reasonable in terms of the onsite equipment, fugitive dust, the concrete batch plant and offsite vehicle use and the offsite vehicle fugitive dust emissions. However, staff recommends additional mitigation measures, specifically the use of CEC-approved soil binders on unpaved roads and other inactive disturbed surfaces during construction, to ensure fugitive dust emissions and associated impacts comply with the applicable standards. Please see the **Soil and Surface Water** section of this **FSA** for more details.

PROJECT OPERATION

The HHSEGS facility would be a nominal 500 Megawatt (MW) heliostat mirror and power tower thermal solar electrical generating facility comprising two plants, HHSEGS Solar Plant 1 (250 MW), and HHSEGS Solar Plant 2 (250 MW) (HHSEGS 2011a). The direct air pollutant emissions from solar power generation are minimal; however, the facility would start-up each day with the assist of natural gas-fueled boilers associated with each plant and there are other equipment and maintenance activities necessary to operate and maintain the facility.

The HHSEGS onsite stationary and mobile emission sources are as follows:

- Each solar plant would include two gas-fired boilers.
- One auxiliary boiler (249 MMBtu) would provide steam prior to sunrise to expedite the process of bringing the solar plants online. During cloudy days or in case of an emergency shutdown, this boiler would also keep the solar generating system hot to facilitate plant restart. The boiler would have a nominal steam production rate of 174,000 lb/hr at 770°F and 655 psia.
- One night preservation boiler would provide steam to the steam turbine generator (STG) and boiler feedwater pump and systems overnight and during other shutdown periods when steam is not available from the solar receiver steam generator (SRSG). The night preservation boiler would have a nominal steam production rate of 10,000 lb/hr at 680°F and 145 psia.
- Each auxiliary boiler would have a maximum of no more than 1,208 equivalent full-load hours of use per year and each nighttime preservation boiler would have a maximum of 5,003 equivalent full-load hours of use per year;
- One 200-bhp diesel-fired emergency fire water pump engine (one for each plant) and one 200-bhp diesel-fueled emergency fire pump, to be located in the common area, would operate in a non-emergency mode for no more than 50 hours per year or no more than required by National Fire Protection Association, whichever is greater;
- One 3,633-bhp diesel-fired emergency generator engine (two for the entire HHSEGS project), and one 398-bhp diesel-fueled emergency generator for the common area would operate in non-emergency mode no more than 50 hours per year;

- Onsite diesel-fueled maintenance vehicles used for mirror washing and other maintenance/operation support activities.

The following assumptions were used to develop the hourly, daily, and annual emissions estimate for HHSEGS operation:

A. Maximum Hourly Emissions

- All boilers are operating.
- All diesel engines operate for one-half hour of duration for readiness testing.

B. Maximum Daily Emissions

- The auxiliary boilers operate up to five equivalent full load hours and up to a total of 7.5 hours per day at low loads, including startup.
- The nighttime preservation boilers operate up to 12 equivalent full-load hours per day during summer months and up to 16 equivalent full-load hours per day during winter months, with an additional hour of low-load operation during startup each day.
- Each emergency generator engine operates half an hour per test.
- Each emergency fire pump engine operates half an hour per test

C. Maximum Annual Emissions

- Each auxiliary boiler was modeled assuming 1,100 full-load hours and 865 startup hours of operation per year.
- Each nighttime preservation boiler was modeled assuming 4,780 full-load hours and 345 startup hours of operation per year.
- Each emergency generator engine was modeled assuming it would operate 50 hours per year for readiness testing purposes.
- Each emergency fire pump engine was modeled assuming it would operate 50 hours per year for readiness testing purposes.

The HHSEGS onsite stationary sources, onsite mobile equipment, and offsite vehicle emissions, including fugitive PM10 emissions, are summarized in **Air Quality Table 8**.

Staff has received the applicants document titled, “Updated Workforce Analysis (Air Quality, Socioeconomics, Traffic and Transportation, and Worker Safety & Fire Protection), which was received by Energy Commission staff docketed October 1, 2012. Staff reviewed the information and found that both the air quality impacts discussed in the AFC and boiler optimization emissions are unchanged. The operations phase of the project remains unchanged because the operations workforce would be slightly reduced.

The direct stationary source emissions from this project are well below the PSD and/or nonattainment NSR permitting applicability thresholds; therefore, the U.S. Environmental Protection Agency (U.S. EPA) and GBUAPCD consider the facility to be a minor stationary source and not expected to create significant impacts.

Air Quality Table 8
HHSEGS Operation - Maximum Hourly, Maximum Daily, and Annual Emissions

	Maximum Hourly Emissions (lbs/hr)					
Emission Source	NOx	SOx	CO	VOC	PM10	PM2.5
Boilers	5.8	1.1	10.2	2.8	2.6	2.6
Emergency Generator Engines	39.8	0.04	22.0	1.4	1.3	1.3
Emergency Fire Pump Engines	2.0	0.01	1.7	0.1	0.1	0.1
WSACs	-	-	-	-	-	<0.01
Maintenance Vehicles (mirror washing)	0.2	0.06	0.01	0.01	0.01	0.01
Maintenance Vehicles (fugitive dust)	-	-	-	-	1.7	0.2
Employee and Delivery Vehicles (offsite)	3.62	0.03	19.15	1.88	1.40	0.37
Total Maximum Hourly Emissions	51.42	1.24	53.06	6.19	7.11	4.59
Emission Source	**Maximum Daily Emissions (lbs/day)**					
Boilers	74.3	7.4	132.5	36.2	19.6	19.6
Emergency Generator Engines	39.8	0.04	22.0	1.4	1.3	1.3
Emergency Fire Pump Engines	2.0	0.01	1.7	0.1	0.1	0.1
WSACs	-	-	-	-	0.4	0.4
Maintenance Vehicles (mirror washing)	4.1	1.1	1.6	1.9	0.1	0.1
Maintenance Vehicles (fugitive dust)	-	-	-	-	34.6	3.5
Employee and Delivery Vehicles (offsite)	20.5	0.2	101.9	10.0	7.4	2.0
Total Maximum Daily Emissions	140.7	8.75	259.7	49.6	63.5	27
Emission Source	**Annual Emissions (tons/year)**					
Boilers	6.3	0.8	11.8	3.0	2.0	2.0
Emergency Generator Engines	2.0	0.01	1.1	0.07	0.06	0.06
Emergency Fire Pump Engines	0.1	0.01	0.1	0.01	0.01	0.01
WSACs	-	-	-	-	0.03	0.03
Maintenance Vehicles (mirror washing)	0.7	0.2	0.03	0.3	0.02	0.02
Maintenance Vehicles (fugitive dust)					6.3	0.6
Employee and Delivery Vehicles (offsite)	1.8	0.0	17.1	1.7	1.2	0.3
Total Annual Emissions	10.9	1.02	30.13	5.08	9.62	3.02

Source: supplemental data responses submitted April 1, 2012 table 5.1-27R and table 5.1-26R (CH2 2012p)

INITIAL COMMISSIONING

Initial commissioning refers to a period of approximately 60 days prior to beginning commercial operation when the equipment undergoes initial tuning and performance tests. Staff does not expect substantial change of emissions from the facility commissioning compared to that of full operation.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assessed three kinds of primary and secondary[7] impacts: construction, operational, and cumulative. Construction impacts result from the emissions occurring during site preparation and construction of the project. Operational impacts result from the emissions of the proposed project during normal operation, which includes all of the

[7] Primary impacts potentially result from facility emissions of NOx, SOx, CO and PM10/2.5. Secondary impacts result from air contaminants that are not directly emitted by the facility but formed through reactions in the atmosphere that result in ozone, and sulfate and nitrate PM10/PM2.5.

onsite auxiliary equipment (boilers, emergency generator, fire pump engine, etc.) and the maintenance vehicle emissions. Cumulative impacts result from the proposed project's incremental effect, together with other closely related past, present and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065(c), 15130, and15355.)

METHOD AND THRESHOLD FOR DETERMINING CEQA SIGNIFICANCE

Energy Commission staff used two main CEQA significance criteria in evaluating this project. First, all project emissions of nonattainment pollutants and their precursors (PM10, NOx, VOC and SO_2) are considered cumulative, CEQA-significant impacts that must be mitigated. Second, any AAQS violation caused by unmitigated project emissions is considered CEQA-significant and must be mitigated. Potentially significant CEQA impacts are deemed to be mitigated to be less than CEQA-significant with the application of appropriate mitigation measures.

For construction emissions, CEQA mitigation is limited to controlling both construction equipment tailpipe emissions and fugitive dust emissions through best practices, to reduce impacts to less than significant.

For operating emissions, when analyzing renewable projects with very low direct criteria pollutant emissions from stationary sources associated with electric generation that: 1) are located in areas with generally good air quality; and 2) are non-attainment of ambient air quality standards primarily or solely due to pollutant transport, the mitigation that is considered is limited to feasible emission controls. These feasible emission controls are applied to both the stationary sources (such as requiring BACT) and the on-site, non-stationary emission sources (such as maintenance vehicles) including associated fugitive dust emission sources.

The ambient air quality standards that staff uses as a basis for determining project CEQA significance are health-based standards established by the ARB and U.S. EPA. They are set at levels to adequately protect the health of all members of the public, including those most sensitive to adverse air quality impacts such as the aged, people with existing illnesses, children, and infants, including a margin of safety.

Impacts from Closure and Decommissioning

Impacts from closure and decommissioning, as a one-time limited duration event, are evaluated with the same methods and thresholds as construction emissions as discussed above.

DIRECT/CUMULATIVE IMPACTS AND MITIGATION

While the emissions are the actual mass of pollutants emitted from the project, the impacts are the concentration of pollutants from the project that reach the ground level. When emissions are released at a high temperature and velocity through a relatively tall stack, the pollutant concentrations would be substantially diluted by the time they reach ground level. The emissions from the proposed project, both stationary source and onsite mobile source emissions, are analyzed by the use of air dispersion models to determine the probable impacts at ground level.

Air dispersion models provide a means of predicting the location and ground level magnitude of the impacts of a proposed new emissions source. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions to provide theoretical maximum offsite pollutant concentrations short-term (1-hour, 3-hour, 8-hour, and 24-hour) and annual periods. The model results are generally described as maximum concentrations expected outside the project's boundary and are often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$).

The applicant has used the U.S. EPA-approved ARMS/EPA Regulatory Model (AERMOD version 1135) air dispersion model to estimate the direct impacts of the project's NOx, PM10, CO, and SOx emissions resulting from project construction and operation. Additionally, boiler emission fumigation impacts during inversion breakup conditions were determined using the U.S. EPA approved SCREEN3 (version 96043) model.

Staff revised the background concentrations provided by the applicant, replacing them with the available highest ambient background concentrations for the last three years from representative monitoring sites show in **Air Quality Table 5**. Staff added the modeled impacts to these background concentrations, then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or would contribute to an existing violation.

The inputs for the air dispersion models include stack information (exhaust flow rate, temperature, and stack dimensions), specific boiler emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Pahrump, Nevada, meteorological site during 2006 and 2011, which is the closest complete meteorological data source to the project site, and supplemented cloud cover data to fill missing information was done by using the Henderson Airport meteorological site. Concurrent upper air data from Elko, Nevada was also used.

Additionally, the applicant obtained hourly ozone and NO_2 ambient data from the Jean Nevada and Trona, CA monitoring stations for 2006 through 2011 that was used in a more refined NO_2 impact modeling analysis using the Ozone Limiting Method (OLM), available with AERMOD that integrates with the downwind plume stoichiometry.

Proposed Project

Construction Impacts Analysis

The HHSEGS project would be constructed in two phases over approximately 29 months. Construction generally consists of two major activities: site preparation, and construction and installation of major equipment and structures. In addition to fugitive dust emissions resulting from the site preparation, emissions from construction equipment exhausts, such as vehicles and internal combustion engines, would also occur during the project construction phase.

Using estimated peak hourly, daily, and annual construction equipment exhaust and fugitive dust emissions, the applicant performed a modeling analysis. **Air Quality Table 9** presents the results of the applicant's modeling analysis.

Air Quality Table 9
Maximum Project Construction Impacts

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background [a] ($\mu g/m^3$)	Total Impact[a] ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr	133.5	117	251	339	74%
	1-hr (98th percentile)	88.0	80.8	169	188	90%
	Annual	3.7	7.5	11	57	19%
PM10	24-hr	29.3	96	125	50	250%
	Annual	1.4	14	15.4	20	77%
PM2.5	24-hr[b]	5.1	13	18	35	46%
	Annual[c]	0.3	4.9	5.2	12	43%
CO	1-hr	66.8	1,750	1,817	23,000	8%
	8-hr	28.3	1,333	1,361	10,000	13%
SO_2	1-hr	0.2	93.6	94	196	48%
	3-hr	0.2	23.4	24	1300	2%
	24-hr	0.05	13.1	13.1	105	12.5%
	Annual	0.01	2.7	2.7	80	3.4%

Source: HHSEGS DResponse set 1A table DR8-4 2011.
Note:
a. Total concentrations shown in this table are the sum of the maximum predicted impact and the maximum measured background concentration. Because the maximum impact would not occur at the same time as the maximum background concentration, the actual maximum combined impact would be lower.
b Background concentration shown is the three-year average of the 98th percentile values, in accordance with the form of the federal standard. Table 5.1F-8, footnote c.
c. Background value shown is the three-year average of the annual arithmetic mean, in accordance with the form of the standard.

This modeling analysis indicates that the project would not create new exceedances and, with the exception of 24-hour PM10 impacts, would not contribute to existing exceedances for any of the modeled air pollutants. Staff notes that the maximum local background 24-hour measurements of PM10, which exceed the state 24-hour PM10 standard with or without the proposed project, may be substantially impacted by wind-blown dust. However, in light of the existing PM10 and ozone non-attainment status for the project site area with regard to state standards, staff considers the construction NOx, VOC, and PM emissions to be potentially CEQA significant and, therefore, staff is recommending that the off-road equipment and fugitive dust emissions be mitigated.

The modeling analysis shows that, after implementation of the recommended fugitive dust mitigation measures, the project's construction is not predicted to cause violations of state or federal AAQS.

Construction Impacts Mitigation

To mitigate the impacts due to construction of the facility, the following mitigation measures have been proposed:

A. All unpaved roads and disturbed areas in the project and for the portion of the linear construction sites located in California would be watered until sufficiently wet to ensure that no visible dust plumes leave the project site.

B. Vehicle speeds would be limited to10 miles per hour within the construction site on unpaved non-stabilized roads.

C. All construction equipment vehicle tires would be washed or cleaned free of dirt prior to entering or leaving the project site.

D. Gravel ramps would be provided at the tire washing/cleaning station.

E. All entrances to the construction site would be graveled or treated with water or dust soil stabilization compounds.

F. Construction areas adjacent to any paved roadway would be provided with sandbags to prevent run-off to the roadway.

G. All paved roads within the construction site would be swept twice daily when construction activity occurs.

H. At least the first 500 feet of any paved public roadway, accessed from the construction site or from unpaved roads en route to the construction site and construction staging areas would be swept regularly on days when construction activity occurs.

I. All soil storage piles and disturbed areas that remain inactive for longer than 10 days would be covered or treated with appropriate dust suppressant compounds.

J. All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions would be provided with a cover, or the materials would be sufficiently wetted and loaded onto the trucks in a manner to provide at least two feet of freeboard.

K. Wind erosion control techniques such as windbreaks, water, chemical dust suppressants, and vegetation would be used on all construction areas that may be disturbed. Any windbreaks used would remain in place until the soil is stabilized or permanently covered with vegetation.

L. Construction equipment would be shut down when not in use in order to avoid excessive idling emissions.

M. Construction equipment would use low sulfur, low aromatic diesel fuel.

N. Construction equipment would be maintained as specified by OEM (original equipment manufacturers) specifications. .

O. Construction equipment used would meet state and federal emission most current standards when available.

Staff recommends the implementation of mitigation measures contained in conditions of certification **AQ-SC1** to **AQ-SC5**, which incorporate the applicant's proposed measures with revisions and additions recommended by staff to further reduce the impacts from the construction of the proposed project. Specific recommendations from staff include a more aggressive dust control requirement to use CPM approved polymer based, or equivalent, soil stabilizers on the site's unpaved roads and inactive disturbed surfaces during construction.

AQ-SC1 would require the project owner to designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with conditions of certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5.**

The AQCMM would have overall responsibility for directing and documenting
The project's compliance with **AQ-SC3** through **AQ-SC5** which are mitigation measures for the site during project construction. Types of actions that can be taken and have been approved by the Energy Commission for other desert projects include but are not limited to:

- Monitoring construction activities for visible dust plumes that have the potential to be transported offsite and within 400 feet of offsite structures not owned by the Owner or 200 feet from the centerline of a linear facility (e.g., pipeline).
- Within 15 minutes of determination of non-compliant dust conditions (associated with construction activity), direct the more intensive application of existing mitigation measures.
- Within 30 minutes of determination of continuing non-compliant dust conditions (associated with construction activity), direct the more intensive application of additional mitigation measures.
- Within 60 minutes of determination of continuing non-compliant dust conditions (associated with construction activities), direct a temporary shutdown of the activity causing the emissions. Activity would not resume until effective mitigation has been implemented or site conditions have changed, such that non-compliant dust conditions would not resume upon restart of the activity.
- Respond to direction from the CPM or BLM Authorized Officer regarding Owner appeals to AQCMM directives.
- Submit related compliance and mitigation measures to the CPM via the Monthly Compliance Report.

The construction of the project would cause particulate matter emissions that would add to existing violations of the state's ambient PM10 air quality standards. Therefore, if unmitigated, the project's construction PM10 emission impacts would be significant. However, staff believes that the implementation of proposed specific mitigation measures during construction of the facility as identified in the conditions of certification would mitigate these short-term impacts of PM10 emissions to a level of less than significant.

Operational Impacts

The following section discusses the project's direct construction/operating ambient air quality impacts, as estimated by the applicant, and evaluated by staff. Additionally, this section discusses Energy Commission staff recommended mitigation measures.

Operational Modeling Analysis

The applicant has provided a modeling analysis using the EPA-approved AERMOD model to estimate the impacts of the project's NOx, PM10, CO, and SOx emissions resulting from project operation and mirror washing activities (CH2 2012p). Similar to the assessment of construction impacts, staff added the modeled impacts to the available highest ambient background concentrations recorded during the previous three years from nearby monitoring stations to assess the project operational impacts. The modeling results, staff recommend backgrounds and total impacts are shown in **Air Quality Table 10**.

This modeling analysis indicates, with the exception of 24-hour PM10 impacts, that the project would not create new exceedances or contribute to existing exceedances for any of the modeled air pollutants. Staff notes that the maximum local background 24-hour measurements of PM10 may be substantially impacted by wind-blown dust. However, in light of the existing PM10 and ozone non-attainment status of state ambient air quality standards for the project site area, staff considers the operating NOx, VOC, and PM emissions to be potentially CEQA significant and, therefore, staff is recommending that the stationary equipment, the off-road maintenance equipment, and fugitive dust emissions be mitigated. The modeling analysis shows that, after implementation of the recommended fugitive dust mitigation measures, the project's operation is not predicted to cause violations of the state or federal AAQS.

Chemically Reactive Pollutant Impacts

The project would have direct emissions of chemically reactive pollutants (NOx, SOx, and VOC), but may also have indirect emission reductions associated with the reduction of fossil-fuel fired power plant emissions due to the project's effect of displacing the need for fossil-fuel power plant operation. The exact nature and location of such reductions are speculative as the overall magnitude and downwind impact of those upwind emission reductions are unknown. Staff's impact analysis has not considered these potential reductions as an offset source for the project's emissions, so the discussion below focuses only on the direct emissions from the project.

Air Quality Table 10
Project Operation with Mirror Washing Emissions Impacts

Pollutants	Avg. Period	Impacts (μg/m³)	Background [a] (μg/m³)	Total Impact (μg/m³)	Standard (μg/m³)	Percent of Standard
NO_2	1-hr	184	--	230[e]	339	68%
	1-hr federal[d]	141	--	166[d]	188	88%
	Annual	0.1	7.5	7.6	57	13%
Pollutants	**Avg. Period**	**Impacts (μg/m³)**	**Background [a] (μg/m³)**	**Total Impact (μg/m³)**	**Standard (μg/m³)**	**Percent of Standard**
PM10	24-hr	**1.1**	**96**	**97.1**	**50**	**194%**
	Annual	0.03	14	14	20	70%
PM2.5 [c]	24-hr [b]	1.1	13	14	35	40%
	Annual	0.03	4.9	4.9	12	40%
CO	1-hr	261.7	1,750	2,011	23,000	9%
	8-hr	64.3	1,333	1,397	10,000	14%
SO2	1-hr	19.0	93.6	112	665	17%
	24-hr [b]	0.5	13.1	13.6	105	23%
	Annual	0.01	2.7	2.7	80	16%

Source: supplemental info from CH2 2012p.
Notes:

a Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.
b Maximum 24-hour hour PM2.5 and SO_2 concentrations occur under fumigation conditions.
c PM2.5 impacts were not remodeled to include maintenance emissions like the other pollutants, the results presented are stationary source emission only from the original AFC modeling analysis. With the maintenance PM2.5 emission the PM2.5 results would be higher than shown but lower than the PM10 results as the PM2.5 emissions are less than the PM10 emissions. Therefore, the PM2.5 impacts with maintenance emissions would not create new exceedances of the ambient air quality standards.
d The total impact for the 1-hour NO_2 federal standard is calculated based on three-year average of 98th percentile of annual distribution of daily maximum paired-sum of project impact and background.
e From applicant value. Includes concurrent 1-hr NO2 modeled impact which were included in the total impact value. See Table 5.1-38 from supplemental data responses submitted April 1, 2012 (CH2 2012p)

Ozone Impacts

There are air dispersion models that can quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the modeling to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from the HHSEGS project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region, which are already designated nonattainment for the state ozone standard.

PM2.5 Impacts

While some PM2.5 would be directly emitted, some PM2.5 forms from precursor emissions and is classified as secondary particulate matter. The process of gas-to-particulate conversion, which occurs downwind from the point of emission, is complex and depends on many factors, including local humidity and the presence of air pollutants. The basic process assumes that the SOx and NOx emissions are converted into sulfuric acid and nitric acid first and then the acids react with ambient ammonia to form sulfate and nitrate. The sulfuric acid reacts with ammonia much faster than nitric acid and converts completely and irreversibly to particulate form. Nitric acid reacts with ammonia to form both a particulate and a gas phase of ammonium nitrate. The particulate phase would tend to fall out; however, the gas phase can revert back to ammonia and nitric acid. Thus, under the right conditions, ammonium nitrate and nitric acid establish a balance of concentrations in the ambient air. There are two conditions that are of interest, described as *ammonia rich* and *ammonia poor*. The term ammonia rich indicates that there is more than enough ammonia to react with all the sulfuric acid and to establish a balance of nitric acid-ammonium nitrate. Further ammonia emissions in this case would not necessarily lead to increases in ambient PM2.5 concentrations. In the case of an ammonia poor environment, there is insufficient ammonia to establish a balance and thus additional ammonia would tend to increase PM2.5 concentrations.

The northeastern San Bernardino County portion of the Great Basin Valleys Air Basin has not undergone the rigorous secondary particulate studies that have been performed in other areas of California, such as the San Joaquin Valley, that have more serious fine particulate pollution problems. However, due to the limited agricultural activity in the area the project site area would likely be characterized as ammonia poor, and the HHSEGS project is not a notable source of ammonia emissions. Therefore, the small amount of operating NOx and SOx emissions generated by this project would have a low potential to create secondary particulate.

***Impact* Summary**

The applicant is proposing to mitigate the project's stationary source NOx, VOC, SO_2, and PM10/PM2.5 emissions through the use of boiler emission controls (Low NOx burner and flue gas recirculation) and natural gas fuel for the boilers, and use emergency engines that meet the highest available EPA/ARB Tier emission standards fueled with California 15 ppm sulfur diesel fuel. Additionally, staff recommends additional mitigation, specified in conditions of certification **AQ-SC6** and **AQ-SC7,** to reduce maintenance vehicle emissions, both tailpipe emission and fugitive dust emissions that could contribute to further ozone and PM10 violations. With the applicant proposed and staff recommended emission mitigation, it is staff's belief that the project would not cause CEQA significant secondary pollutant impacts.

Operations Mitigation

Applicant's Proposed Mitigation

Emission Controls

As discussed in the air quality section of the AFC (HHSEGS 2011a), the applicant proposes the following emission controls on the stationary equipment associated with the HHSEGS operation:

Auxiliary Boilers (Startup Boilers)

The applicant's proposed mitigation for each auxiliary boiler includes Low-NOx burners and 20 percent flue gas recirculation (for NOx), good combustion practices (for CO), and to operate each exclusively on pipeline quality natural gas (for VOC, PM and SOx) to limit boiler emission levels. The AFC (HHSEGS 2011a), and Determination of Compliance (DOC) conditions (GBUAPCD 2012a) provide the following emission limits, for each of the auxiliary boilers:

- NOx: 9.0 ppmvd at 3% O_2 (one-hour average), 2.74 lb/hour
- CO: 25 ppmvd at 3% O_2 (one-hour average), 4.55 lb/hour
- VOC as CH_4: 12.6 ppmvd, 1.34 lb/hour
- PM10/PM2.5: 1.25 lb/hour
- SO_2: 1.7 ppmvd, 0.52 lb/hour

Nighttime Preservation Boilers

The applicant's proposed mitigation for each preservation boiler includes Low-NOx burners and 20 percent flue gas recirculation (for NOx), good combustion practices (for CO), and to operate each exclusively on pipeline quality natural gas (for VOC, PM and SOx) to limit boiler emission levels. The supplemental data responses submitted by the applicant on April 2, 2012 (CH2 2012p), and final FDOC conditions would require the following emission limits for each of the nighttime preservation boilers:

- NOx: 9.0 ppmvd at 3% O_2 (one-hour average), 0.17 lb/hour
- CO: 50 ppmvd at 3% O_2 (one-hour average), 0.55 lb/hour
- VOC: 12.6 ppmvd, 0.08 lb/hour
- PM10/PM2.5: 0.08 lb/hour
- SO_2: 1.7 ppmvd, 0.03 lb/hour

Emergency Backup Engines

The applicant's proposed controls for each emergency generator engine is to purchase a new engine meeting current emission standard requirements (currently, Tier 2) for 3,633 bhp engines. The specific emission levels for the selected engine are currently unknown but they would be no higher than following Tier 2 emission standards:

- NOx: 4.8 grams per brake horsepower
  (including non-methane hydrocarbons - NMHC/VOC)
- CO: 2.6 grams per break horsepower
- VOC: 0.16 grams per break horsepower
- PM10: 0.15 grams per break horsepower
- SO_2: 15 ppm sulfur content fuel

Fire Water Pump Engines

The applicant has proposed use of Tier 3 Engines that would have emission rates no greater than the following standards:

- NOx: 3.0 grams per break horsepower (including NMHC/VOC)

- CO: 2.6 grams per break horsepower
- VOC: (see NOx above)
- PM10: 0.15 grams per break horsepower
- SO_2: 15 ppm sulfur content fuel

Maintenance Vehicles

The applicant has proposed to use on-road or certified off-road vehicles and engines for mirror washing and other maintenance activities to minimize emissions for this emission source.

Delivery and Employee Vehicles

The applicant has not proposed any specific emission controls for this emission source.

Emission Offsets

The applicant has not proposed any emission offsets and the stationary source emissions for HHSEGS as currently proposed by the applicant would be well below District offset thresholds.

Adequacy of Proposed Mitigation

Staff concurs with the District's determination that the project's stationary source proposed emission controls/emission levels for criteria pollutants meet regulatory requirements and that the proposed stationary source emission levels are reduced adequately.

Staff Proposed Mitigation

As mentioned earlier in the discussions of the ozone and PM10 impacts, staff believes that the project's ozone precursors and PM10 emissions, if unmitigated, could cause CEQA significant impacts. Additionally, staff believes a solar renewable project, which would have a 30 to 40-year life, located in an ozone and PM10 nonattainment area and just downwind of other ozone and PM10 nonattainment areas, should address its contribution to the potentially ongoing nonattainment of the PM10 and ozone standards. Therefore, staff recommends the following additional mitigation measures:

- Require the use of new model year vehicles for onsite maintenance, or equivalently low emitting vehicles as long as those vehicles can be demonstrated to have a similar or lower emission profile than new model year vehicles
- Limit vehicle speeds within the facility to no more than ten miles per hour on unpaved areas that have not undergone soil stabilization, and up to 25 miles per hour, or greater with CPM approval as long as there is no conflict with **BIO-7(3)**, on stabilized unpaved roads as long as no visible dust plumes are observed, to address fugitive PM emissions from the site;
- Apply and maintain water or other non-toxic soil binder[8] to the onsite unpaved roads to create a durable stabilized surface;

[8] The soil stabilizer product used will require prior approval by the Energy Commission.

- Additional ongoing operations fugitive dust emissions control techniques such as windbreaks, trackout controls, etc. should be identified in a fugitive dust control plan and used on areas that could be disturbed by vehicles or wind. Any windbreaks used would remain in place until the soil or road is stabilized.

Staff further recommends that onsite maintenance vehicles and ongoing fugitive dust emissions control are subject to conditions of certification **AQ-SC6** and **AQ-SC7**, respectively. Staff also proposes condition of certification **AQ-SC8** to ensure that the license is amended as necessary to incorporate changes to the air quality permits and **AQ-SC9** to require submittal of Quarterly Operation Reports.

Staff believes that the implementation of these recommended additional CEQA mitigation measures would reduce the potential of adverse impacts from the facility on ozone and PM10 to levels less than significant.

Staff has considered the presence of minority populations near to the site (see **Socioeconomics Figure 1**). The demographic analysis indicates no environmental justice population. Moreover, since the staff-proposed mitigation measures reduce the project's air quality impacts to a level that is less than significant, there is no environmental justice issue for air quality.

Closure and Decommissioning Impacts and Mitigation

Eventually the facility would close, either at the end of its useful life or due to some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, all sources of air emissions would cease to operate and thus impacts associated with those emissions would no longer occur. The only other expected emissions would be equipment exhaust and fugitive particulate emissions from any dismantling activities. These activities would be of much a shorter duration than construction of the project, equipment are assumed to have much lower comparative emissions due to technology advancement during the intervening years, and fugitive dust emissions would be required to be controlled in a manner at least equivalent to that required during construction. Therefore, while there would be adverse CEQA-related air quality impacts during decommissioning they are expected to be less than significant. At the time of decommissioning, the applicant will be required to obtain Energy Commission approval of a plan to control wind-blown dust emission until a natural crust is developed.

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts." (CEQA Guidelines, § 15355) A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts." (CEQA Guidelines, § 15130(a)(1).) Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This air quality analysis is concerned with *criteria* air pollutants. Such pollutants have impacts that are usually (though not always) cumulative by nature. However, a new source of pollution may contribute to existing violations of criteria pollutant standards because of the existing background sources or foreseeable future projects. Air districts attempt to attain the criteria pollutant standards by adopting attainment plans, which comprise a multi-faceted programmatic approach to such attainment. Depending on the air district, these plans typically include requirements for air offsets and the use of Best Available Control Technology (BACT) for new sources of emissions, and restrictions of emissions from existing sources of air pollution.

Much of the preceding discussion is concerned with cumulative impacts. The “Existing Ambient Air Quality” subsection describes the air quality background in southeastern Inyo County portion of the Great Basin Valleys Air Basin, including a discussion of historical ambient levels for each of the assessed criteria pollutants. The “Construction Impacts and Mitigation” subsection discusses the project’s contribution to the local existing background caused by project construction. The “Operation Impacts and Mitigation” subsection discusses the project’s contribution to the local existing background caused by project operation. The following subsection includes two additional analyses:

- a summary of projections for criteria pollutants by the air district and the air district’s programmatic efforts to abate such pollution;
- an analysis of the project’s *localized cumulative impacts*, the project’s direct operating emissions combined with other local major emission sources;

Summary of Projections

The southeastern Inyo County portion of the GBVAB is designated as non-attainment for state PM10 and ozone ambient air quality standards and attainment/unclassified for the federal PM10 and ozone ambient air quality standards. PM2.5, CO, NO_2, and SO_2 are all considered to be attainment or unclassified for the federal and state standards.

Ozone

A portion of Inyo County in the Mojave Desert is non-attainment for the state standard, north and west of the project site. With respect to state standards, the entire GBUAPCD is classified as nonattainment for the 8-hour ozone standard, with the exception of Alpine County; and either unclassified (Alpine and Inyo counties) or nonattainment (Mono County) for the 1-hour state ozone standard.

On May 21, 2012, in the Federal register (Vol 77, No. 98)the US EPA redesignated all of Inyo County as unclassifiable/attainment for the federal 8-hour ozone standard. Thus, currently there is no requirement for the GBUAPCD to prepare a federal attainment plan for the 8-hour federal ozone standard.

Particulate Matter

The District is nonattainment for the state 24-hour PM10 air quality standard. California has adopted standards that are far more stringent than federal requirements for PM10. Currently, virtually all air districts in the state (the lone exception being Lake County) are designated nonattainment of the state PM10 standard. There is no legal requirement for air districts to provide plans to attain the state PM10 standard, so air districts have not developed such plans.

In 1997, the federal government adopted PM2.5 standards, as did the state in 2003. The EPA has determined that the area is unclassified, or attainment for both the annual and the 24-hour federal PM2.5 standard.

As a solar power generation facility, the direct air pollutant emissions from power generation are negligible and the emission sources are limited to auxiliary equipment and maintenance activities. With the mitigation required by the recommended staff conditions and District conditions, the project will not have a CEQA significant impact on particulate matter emissions.

Summary of Conformance with Applicable Air Quality Plans

The applicable air quality plans do not outline any new control measures applicable to the proposed project's operating emission sources. Therefore, compliance with existing District rules and regulations would ensure compliance with those air quality plans.

Localized Cumulative Impacts

Since HHSEGS air quality impacts can be reasonably estimated through air dispersion modeling (see the "Operational Modeling Analysis" subsection) the project's contribution to localized cumulative impacts can be estimated. To represent *past* and, to an extent, *present projects* that contribute to current ambient air quality conditions, the Energy Commission staff recommends the use of ambient air quality monitoring data (see the "Environmental Setting" subsection), referred to as the *background*. The staff takes the following steps to estimate what are additional appropriate "present projects" that are not represented in the background and "reasonably foreseeable projects":

- First, the Energy Commission staff (or the applicant) works with the air district to identify all projects that have submitted, within the last year of monitoring data, new applications for an authority to construct (ATC) or permit to operate (PTO) and applications to modify an existing PTO within six miles of the project site. Based on staff's modeling experience, beyond six miles there is no significant concentration overlap for non-reactive pollutant concentrations between two stationary emission sources.
- Second, the Energy Commission staff (or the applicant) works with the air district and local counties to identify any new area sources within six miles of the project site. As opposed to point sources, area sources include sources like agricultural fields, residential developments or other such sources that do not have a distinct point of emission. New area sources are typically identified through draft or final Environmental Impact Reports (EIRs) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is "reasonably foreseeable" for new area sources.
- The data submitted, or generated from the applications with the air district for point sources or initiating the EIR process for area sources, provides enough information to include these new emission sources in air dispersion modeling. Thus, the next

step is to review the available EIR(s) and permit application(s), then determine what sources must be modeled and how they must be modeled.

- Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources include existing sources that are co-located with or adjacent to the proposed source (such as an existing power plant). In most cases, the ambient air quality measurements are not recorded close to the proposed project, thus a local major source might not be well represented by the background air monitoring data. When these sources are included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than two miles away.
- The modeling results must be carefully interpreted so that they are not skewed towards a single source, in high impact areas near that source's fence line. It is not truly a cumulative impact of the HHSEGS if the high impact area is the result of high fence line concentrations from another stationary source which is not providing a substantial contribution to the determined high impact area.

Once the modeling results are interpreted, they are added to the background ambient air quality monitoring data and thus the modeling portion of the cumulative assessment is complete. Due to the use of air dispersion modeling programs in staff's cumulative impacts analysis, the applicant must submit a modeling protocol, based on information requirements for an application, prior to beginning the investigation of the sources to be modeled in the cumulative analysis. The modeling protocol is typically reviewed, commented on, and eventually approved in the Data Adequacy phase of the licensing procedure. Staff typically assists the applicant in finding sources (as described above), characterizing those sources, and interpreting the results of the modeling. However, the actual modeling runs are usually left to the applicant to complete. There are several reasons for this: modeling analyses take time to perform and require substantial expertise, the applicant has already performed a modeling analysis of the project alone (see the "Operational Modeling Analysis" subsection), and the applicant can act on its own to reduce stipulated emission rates and/or increase emission control requirements as the results warrant. Once the cumulative project emission impacts are determined, the necessity to mitigate the project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or the applicant (see the "Mitigation" subsection).

The applicant, in consultation with the district, has conducted a survey of stationary sources that are either under construction, or have received permits to be built or operate in the near future and that have the potential for emissions of criteria air contaminants within six miles of the project site. The survey results indicate that no such sources exist within 6-miles from the project boundaries[9] of the proposed project site (CH2 2012p).

The Applicant requested information for a cumulative impact analysis from the GBUAPCD, Nevada's Clark County Department of Air Quality and Environmental Management, and the Nevada Division of Environmental Protection, Department of Air Quality Management, Bureau of Air Pollution Control ("Nevada DEP"). The request

[9] Staff assumes that impacts from projects beyond six miles would not affect the modeling analysis on a cumulative basis. This is in the CA Energy Commission's "Siting Rules and Regulations of Practice and Procedure and Power Plant Siting Regulations, April 2007"; Title 20, California Code of Regulations, Chapter 5, Appendix B, section 8, (I)(iii).

letters and any agency responses received before the AFC was filed were included in Attachment 5.1G-1 to Appendix 5.1G of the AFC. To summarize, the GBUAPCD responded that:

> *"[t]here are no facilities in the District, other than the St. Therese project, within 6 miles of the <u>perimeter</u> of the Hidden Hills Ranch project." Nevada DEP responded with a list of active permits in the general project area. Attachment 5.1G-1 includes the list provided by Nevada DEP and a description of the analysis used to determine that none of the projects on the list provided by Nevada DEP is within 6 miles of the project site. The Clark County response to the request for information regarding potential sources to be included in a cumulative impact analysis was received on August 25, 2011, after the AFC had been filed, and was docketed on August 29. Clark County responded: We have five permitted sources in, or near, that hydrographic area, but, none of these are within the 6 miles perimeter of the site you have identified. In fact, it appears the closest permitted source is over 20 miles away. Our search of our records did not indicate any proposed authority to construct projects within the area for which we have received an application.*

No additional cumulative air quality impact modeling analysis was performed, and no CEQA significant cumulative air quality impacts are expected. after implementation of staff's recommended project mitigation measures. However, staff is aware of a tremendous potential development of wind and solar in the desert southwest of the United States, and in the area where HHSEGS would be located. While the number of renewable project filings is much larger than what would eventually be built and operated in the desert southwest, staff believes it is appropriate to construct and operate all desert renewable projects with best practices to reduce any potential cumulative effects, including criteria pollutants and their contributions to region ozone and particulate matter and haze. Staff recommends conditions of certification **AQ-SC1** and **AQ-SC-7** as best practices for the construction and operation of the HHSEGS desert solar project.

Staff has considered the minority population surrounding the site (see **Socioeconomics Figure 1**). Since the project's cumulative CEQA air quality impacts have been mitigated to be less than significant, there is no environmental justice issue for air quality.

COMPLIANCE WITH LORS

The Great Basin Unified Air Pollution Control District issued the Final Determination of Compliance (FDOC) for the HHSEGS on August 1, 2012 and the FDOC was docketed by the Energy Commission on August 8, 2012 (GBUAPCD 2012b). The FDOC finds compliance e with all District rules and regulations. The District's conditions are presented below in the "**AQ-x**" series of conditions of certification.

FEDERAL

The district is responsible for issuing the federal New Source Review (NSR) permit, the federal Title V permit, and has been delegated enforcement of the applicable New Source Performance Standard (Subparts, Dc, Db, and IIII). The applicant would be required to submit a Title V permit application to the district within 12 months of commencing operation. Additionally, this project would not require a PSD permit from U.S. EPA, because the project would be below the 250 tons per year (TPY) threshold for criteria pollutants and less than 100,000 tpy of GHG pollutants.

STATE

The project would comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury, with the issuance of the District's Final Determination of Compliance and the Energy Commission's affirmative finding for the project. In the FDOC, the district concluded that the project would comply with this requirement as the screening health risk assessment they performed found risks to be below a Prioritization Score of 1.0, or below the need for any additional analysis or action. For additional information on health risks, refer to the Public Health portion of the FSA.

The fire pump and emergency generator engines are also subject to the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines (17 CCR §93115). This measure limits the types of fuels allowed, established maximum emission rates and establishes recordkeeping requirements. This measure would also limit the engine's testing and maintenance operation to 50 hours per year. The engines would also meet the current Tier standards of 13 CCR, §2423 - Exhaust Emission Standards and Test Procedures: Heavy-Duty Off-Road Diesel Cycle Engines.

LOCAL

The District rules and regulations specify the emissions control and offset requirements for new sources such as the HHSEGS. The emitting equipment would be well controlled; however, Best Available Control Technology (BACT), and emission reduction credits (ERCs) are not required by District rules and regulations based on the permitted stationary source emission levels for this project. Compliance with the District's new source requirements would ensure that the project would be consistent with the strategies and future emissions anticipated under the District's air quality attainment and maintenance plans.

The applicant provided an air quality permit application to the GBUAPCD in September 2011 and the District issued the FDOC on August 1, 2012. This Final Determination of Compliance (FDOC) evaluated whether and under what conditions the proposed project would comply with the District's applicable rules and regulations, as described below.

Regulation II – New Source Review

Rule 216 – New Source Review

This rule requires implementation of BACT for any emission source unit that emits or has the potential to emit 250 lbs/day or more, and emission offsets if total facility emissions exceed annual thresholds. The district permits limit the emissions from each source to less than 250 lbs/day, so BACT is not applicable; and the permits limit the total site annual emission below offset thresholds, so offsets are not required.

Regulation II – Permits

Rule 200 and 209A – Permit to Construct and Permit to Operate

Rule 200 establishes the emission source requirements that must be met to obtain a Permit to Construct. Rule 209A prohibits use of any equipment or the use of which may emits air contaminants without obtaining a Permit to Operate. The applicant has submitted all required applications; therefore, the applicant is in compliance with these rules.

Rule 217 – Federal Operating Permit Requirement

Rule 217 requires certain facilities to obtain Federal Operating Permits. The auxiliary boilers, by providing steam to a steam turbine having a capacity greater than 25 megawatts of electrical output, trigger Title IV – Acid Deposition Control for this project. Title V permitting is thereby also required for the proposed project. The applicant would be required to submit an application for a Title V permit to the district to comply with this rule.

Regulation IV – Prohibitions

Rule 400 - Visible Emissions Opacity Limit

This rule limits visible emissions from emissions sources, including stationary source exhausts and fugitive dust emission sources. Compliance with this rule is expected.

Rule 401 - Fugitive Dust

This rule limits fugitive emissions from certain bulk storage, earthmoving, construction and demolition, and manmade conditions resulting in wind erosion. With the implementation of recommended staff condition **AQ-SC3** and **AQ-SC7,** the facility would comply with this rule.

Rule 402- Nuisance

This rule restricts discharge of emissions that would cause injury, detriment, annoyance, or public nuisance. The facility would comply with this rule (identical to California Health and Safety Code 41700).

Rule 403 - Breakdown

This rule sets forth procedures that must be followed in the event of an unforeseeable failure or breakdown of air pollution control equipment. The facility would comply with this rule.

Rule 404-A - Particulate Matter Concentration

Rule 404.A limits particulate matter (PM) emissions to less than 0.3 grains per standard cubic foot of gas at standard conditions. In the DOC, the District has determined that the estimated PM emission concentrations of the proposed boilers and engines are less than permit limits. These proposed emission rates are well below the limits established by this rule, therefore compliance is expected.

Rule 404-B – Oxides of Nitrogen

This rule applies to fuel-burning equipment with a maximum heat input rate in excess of 1.5 billion Btu/hr (gross) (1500 MMBtu/hr HHV). All of the fuel burning equipment proposed for installation at HHSEGS has a maximum heat input rate below this threshold, so this rule is not applicable to the project.

Rule 416 – Sulfur Compounds and Nitrogen Oxides

This rule prohibits emissions from a single source in excess of the following:

- Sulfur compounds as SO2: 0.2 percent by volume
- NOx, calculated as NO2: 140 lb/hr from any new boiler

These proposed emission rates are well below the limits established by this rule, therefore compliance is expected.

Regulation IX – Standards of Performance for New Stationary Sources

This regulation incorporates the Federal NSPS (40 CFR 60) rules by reference. The district evaluated compliance with Subpart Db that applies to the HHSEGS auxiliary boiler and Subpart Dc that applies to the nighttime preservation boilers and has provided conditions they believe ensure compliance with these regulations.

The requirements of Subpart Db, Standards of Performance for Industrial-Commercial-

Institutional Steam Generating Units, are applicable to the startup boilers. For natural-gas fired units, Subpart Db includes the following emission limits:

- NOx: 0.20 lb/MMBtu (24-hour average basis)
- SO2: 0.20 lb/MMBtu

The requirements of Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, are applicable to the nighttime preservation boilers. For these small natural-gas-fired units, Subpart Dc includes the following emission limit:

- SO2: 0.5 lb/MMBtu

The PM limits of Subpart Dc do not apply to boilers with a heat input capacity below 30 MMBtu/hr, such as the nighttime preservation boilers.

Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines would be applicable to the emergency engines and the fire pump engines.

Both the proposed Tier II and Tier III Emergency IC Engine (large generators) and the Fire Pump engines, respectively, meet the emission limit requirements of the NSPS ((Subpart IIII).

NOTEWORTHY PUBLIC BENEFITS

Renewable energy facilities, such as the HHSEGS, would help meet California's mandated renewable energy goals. These goals are part of a comprehensive strategy to reduce the state's greenhouse gas emissions by replacing megawatts (mw) from fossil-fueled generation, thereby reducing the contribution of such emissions to climate change.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

There have been public agency comments on staff's air quality section from Inyo County, comments from Intervener Cindy MacDonald and public comments from Basin and Range Watch that were submitted following the publication of the Preliminary Staff Assessment (PSA) in a manner that require a technical response. Some comments resulted in text changes and others are responded to in **Appendix 1 - PSA Response to Comments, Air Quality**. The applicant has also provided comments (CH2 2012q) that have been addressed by staff. Some of these comments resulted in minor text modifications, as staff deemed appropriate. The appendix describes how staff responded to these comments.

CONCLUSIONS

Staff makes the following conclusions about the HHSEGS:

- The project will not exceed PSD emission levels during direct source operation and the facility is not considered a major stationary source with potential to cause significant air quality impacts. However, without adequate fugitive dust mitigation, the project would have the potential to cause localized exceedances of the PM10 NAAQS during construction and operation. Recommended conditions of certification **AQ-SC1** through **AQ-SC4**, for construction, and **AQ-SC7**, for operation, would mitigate these potentially significant impacts.
- The project would comply with applicable district rules and regulations, including New Source Review requirements; staff recommends the inclusion of the Districts DOC conditions as conditions of certification **AQ-1** through **AQ-33** for the Hidden Hills Power Plants, and **AQ-1**, **AQ-3** though **AQ-8** and **AQ-34** through **AQ-44** for the facility's common area.
- Staff concludes the project's construction activities would likely contribute to significant adverse PM10 and ozone impacts without additional mitigation. Staff recommends **AQ-SC1** to **AQ-SC5** to mitigate potential impacts.
- Staff concludes the project's operation would not cause new violations of any NO_2, SO_2, PM2.5 or CO ambient air quality standards; therefore, the project's direct operational NOx, SOx, PM2.5 and CO emission impacts are not significant.
- Staff concludes the project's direct and indirect (or secondary) emissions contribution to existing violations of the ozone and PM10 ambient air quality standards are likely significant if unmitigated. Therefore, staff recommends **AQ-SC6** to mitigate the onsite maintenance vehicle emissions and **AQ-SC7** to mitigate the

operating fugitive dust emissions to ensure that the potential ozone and PM10 CEQA impacts are mitigated to less than significant over the life of the project.

STAFF PROPOSED FINDINGS OF FACT

Based on the staff's analysis, we recommend the following findings:

1. The HHSEGS project would be located in the Great Basin Valleys Air Basin under the local jurisdiction of the Great Basin Unified Air Pollution Control District.

2. The HHSEGS project area is designated as nonattainment for the state ozone standard, attainment/unclassified for federal ozone standards, nonattainment for the state 24-hour PM10 standard, and attainment or unclassified for the state and federal CO_2, NO_2, SO_2, and PM2.5 standards.

3. The project would not cause new violations of any NO_2, SO_2, PM2.5, or CO ambient air quality standards. Therefore, the NO_x, SO_x, PM2.5, and CO emission impacts are not significant.

4. The project's NO_x and VOC emissions could contribute to existing violations of the state's ozone standard during construction and operation. However, the required mitigation would reduce the project's impacts to a level that is less than significant.

5. The project's PM10 emissions could contribute to existing violations of the state 24-hour PM10 air quality standard during construction and operation. However, the required mitigation set forth in conditions **AQ-SC1** though **AQ-SC7** would reduce the project's impacts to a level that is less than significant.

6. The Great Basin Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) finding that HHSEGS would comply with all applicable district rules and regulations for project operation. The district's proposed FDOC conditions are included herein as conditions of certification **AQ-1** through **AQ-33** for each of the two Hidden Hills Power Plants and **AQ-1** though **AQ-8**, and **AQ-34** through **AQ-44** for the common area.

7. The cumulative air quality impacts analysis demonstrates that the project would not result in a significant cumulative impact.

8. Implementation of the conditions of certification listed below would ensure that the HHSEGS facility would not result in any significant direct, indirect, or cumulative adverse impacts to air quality.

MITIGATION MEASURES/ PROPOSED CONDITIONS OF CERTIFICATION

STAFF CONDITIONS OF CERTIFICATION

Staff conditions **AQ-SC1** through **AQ-SC9** are all CEQA-only mitigation measures associated with construction and operation of the proposed facility.

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with conditions of certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5** for the project site and the portions of the linear facility constructed in California. The on-site AQCMM may delegate responsibilities to one or more AQCMM Delegates. The AQCMM and AQCMM Delegates shall have full access to all areas of construction on the project site and linear facilities located in California, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM Delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the Compliance Project Manager (CPM).

<u>Verification:</u> At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM Delegates.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with conditions of certification **AQ-SC3**, **AQ-SC4,** and **AQ-SC5**.

<u>Verification:</u> At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The AQCMP shall include effectiveness and environmental data for the proposed soil stabilizer. The CPM will notify the project owner of any necessary modifications to the plan within 15 business days from the date of receipt.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report (MCR) that demonstrates compliance with the following mitigation measures for the purposes of preventing all fugitive dust plumes from leaving the project boundary. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

A. The main access roads through the facility to the power block areas will be paved prior to initiating construction in the main power block area, and delivery areas for operations materials (chemicals, replacement parts, etc.) will be paved prior to taking initial deliveries.

B. All unpaved construction roads and unpaved operational site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as ARB-approved soil stabilizers, and shall not increase any other environmental impacts including loss of vegetation. All other disturbed areas in the project and linear construction sites shall be watered as frequently as necessary during grading and stabilized with a non-toxic soil stabilizer or soil weighting agent to comply with the dust mitigation objectives of condition of certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

C. No vehicle shall exceed 10 miles per hour on unpaved areas within the construction site, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

D. Visible speed limit signs shall be posted at the construction site entrances and along traveled routes.

E. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

F. Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

G. All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

H. All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

I. Construction areas adjacent to any paved roadway shall be provided with sandbags or other equivalently effective measures to prevent run-off to roadways, or other similar run-off control measures as specified in the Storm Water Pollution Prevention Plan (SWPPP), only when such SWPPP measures are necessary so that this condition does not conflict with the requirements of the SWPPP.

J. All paved roads within the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

K. At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff resulting from the construction site activities is visible on the public paved roadways.

L. All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or shall be treated with appropriate dust suppressant compounds.

M. All vehicles used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.

N. Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

Verification: The AQCMM shall provide the CPM a MCR (**COMPLIANCE-6**) to include:

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the district in relation to project construction; and

C. any other documentation deemed necessary by the CPM, and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner’s discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM or an AQCMM Delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported: (A) off the project site and within 400 feet upwind of any regularly occupied structures not owned by the project owner, or (B) 200 feet beyond the centerline of the construction of linear facilities indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the augmented mitigation measures will be accomplished within the time limits specified in steps 1 through 3, below. The AQCMM or Delegate shall implement the following procedures for augmented mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM or Delegate shall direct implementation of augmented methods of dust suppression if Step 1, specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM or Delegate shall direct a temporary shutdown of the activity causing the emissions if Step 2, specified above, fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, if the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMM shall provide the CPM a MCR (**COMPLIANCE-6**) to include:

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the District and provided to the project owner in relation to project construction; and

C. any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition.

AQ-SC5 Diesel-Fueled Engine Control: The AQCMM shall submit to the CPM, in the MCR, a table that demonstrates compliance with the AQCMP mitigation measures for purposes of controlling diesel construction-related combustion emissions. Any deviation from the AQCMP mitigation measures requires prior CPM notification and approval.

All off-road diesel construction equipment with a rating of 50 hp or greater used in the construction of this facility shall be powered by the cleanest engines available that also comply with the California Air Resources Board's (ARB's) Regulation for In-Use Off-Road Diesel Fleets (California Code of Federal Regulations Title 13, Article 4.8, Chapter 9, Section 2449 et.seq.) and shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**. The AQCMP measures shall include the following, with the lowest-emitting engine chosen in each case, as available:

a. All off-road vehicles with compression ignition engines shall comply with the California Air Resources Board's (ARB's) Regulation for In-Use Off-Road Diesel Fleets.

b. To meet the highest level of emissions reduction available for the engine family of the equipment, each piece of diesel-powered equipment shall be powered by a Tier 4 engine (without add-on controls) or Tier 4i engine (without add-on controls), or a Tier 3 engine with a post-combustion retrofit device verified for use on the particular engine powering the device by the ARB or the US EPA. For PM, the retrofit device shall be a particulate filter if verified, or a flow-through filter, or at least an oxidation catalyst. For NOx, the device shall meet the latest Mark level verified to be available (as of January 2012, none meet this NOx requirement).

c. For diesel powered equipment where the requirements of Part “b” cannot be met, the equipment shall be equipped with a Tier 3 engine without retrofit control devices or with a Tier 2 or lower Tier engine using retrofit controls verified by ARB or US EPA as the best available control device to reduce exhaust emissions of PM and nitrogen oxides (NOx) unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices can be considered “not practical” for the following, as well as other, reasons:

   1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection Agency to control the engine in question and the highest level of available control using retrofit or Tier 1 engines is being used for the engine in question; or

   2. The use of the retrofit device would unduly restrict the vision of the operator such that the vehicle would be unsafe to operate because the device would impair the operator’s vision to the front, sides, or rear of the vehicle, or

   3. The construction equipment is intended to be on site for 10 work days or less.

d. The CPM may grant relief from a requirement in Part “b” or “c” if the AQCMM can demonstrate a good faith effort to comply with the requirement and that compliance is not practical.

e. The use of a retrofit control device may be terminated immediately provided that: (1) the CPM is informed within 10 working days following such termination; (2) a replacement for the construction equipment in question, which meets the level of control required, occurs within 10 work days following such termination of the use (if the equipment would be needed to continue working at this site for more than 15 work days after the use of the retrofit control device is terminated); and (3) one of the following conditions exists:

   1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in exhaust back pressure.

   2. The retrofit control device is causing or is reasonably expected to cause engine damage.

   3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.

   4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

f. All equipment with engines meeting the requirements above shall be properly maintained and the engines tuned to the engine manufacturer's specifications. Each engine shall be in its original configuration and the equipment or engine must be replaced if it exceeds the manufacturer's approved oil consumption rate.

g. Construction equipment will employ electric motors when feasible.

h. If the requirements detailed above cannot be met, the AQCMM shall certify that a good faith effort was made to meet these requirements and this determination must be approved by the CPM.

All off-road diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

Verification: The AQCMM shall include in the MCR the following to demonstrate control of diesel construction-related emissions:

A. A summary of all actions taken to control diesel construction related emissions;

B. A table listing list of all heavy equipment used on site during that month, showing the tier level of each engine and the basis for alternative compliance with this condition for each engine not meeting Part "b" requirements. The MCR shall identify the owner of the equipment and contain a letter from each owner indicating that the equipment has been properly maintained; and

C. Any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. \

AQ-SC6 The project owner, when obtaining dedicated vehicles for mirror washing activities and other facility maintenance activities, shall only obtain new model year vehicles that meet California on-road or EPA non-road vehicle emission standards for the year when obtained.

Other vehicle/fuel types may be allowed assuming that the emission profile for those vehicles, including fugitive dust generation emissions, is comparable to the vehicles types identified in this condition.

Verification: At least 60 days prior to the start of commercial operation, the project owner shall submit to the CPM a plan that identifies the size and type of the on-site vehicle and equipment fleet and the vehicle and equipment purchase orders and contracts and/or purchase schedule. The plan shall be updated every other year and submitted in the Annual Compliance Report (**COMPLIANCE-7**).

AQ-SC7 The project owner shall provide a site operations dust control plan, including all applicable fugitive dust control measures identified in **AQ-SC3** that would be applicable to reducing fugitive dust from ongoing operations; that:

A. describes the active operations and wind erosion control techniques such as windbreaks and chemical dust suppressants, including their ongoing maintenance procedures, that shall be used on areas that could be disturbed by vehicles or wind anywhere within the project boundaries; and

B. identifies the location of signs throughout the facility that will limit traveling on unpaved surfaces to solar equipment maintenance vehicles only. In addition, vehicle speed shall be limited to no more than 10 miles per hour on these unpaved surfaces, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved surfaces as long as such speeds do not create visible dust emissions.

The site operations fugitive dust control plan shall include the use of durable non-toxic soil stabilizers on all regularly used unpaved roads and disturbed off-road areas within the project boundaries, and shall include the inspection and maintenance procedures that will be undertaken to ensure that the unpaved roads remain stabilized. The soil stabilizer used shall be a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as ARB approved soil stabilizers, and shall not increase any other environmental impacts including loss of vegetation.

The fugitive dust controls shall meet the performance requirements of condition **AQ-SC4**. The performance requirements of **AQ-SC4** shall also be included in the operations dust control plan.

At the time of decommissioning, the applicant is required to obtain Energy Commission approval to control wind-blown dust emissions until a natural crust is developed as part of the project owner's long-term dust control plan.

Verification: At least 60 days prior to start of commercial operation, the project owner shall submit to the CPM for review and approval a copy of the plan that identifies the dust and erosion control procedures, including effectiveness and environmental data for the proposed soil stabilizer, that will be used during operation of the project and that identifies all locations of the speed limit signs. At least 60 days after the beginning of commercial operation, the project owner shall provide to the CPM a report identifying the locations of all speed limit signs, and a copy of the project employee and contractor training material that clearly identifies that project employees and contractors are required to comply with the dust and erosion control procedures and on-site speed limits.

AQ-SC8 The project owner shall provide the CPM copies of all district issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility.

The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the district or U.S. Environmental Protection Agency (U.S. EPA), and any revised permit issued by the district or U.S. EPA for the project.

Verification: The project owner shall submit any ATC, PTO, and proposed air permit modifications to the CPM within 5 working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all approved modified air permits to the CPM within 15 days of receipt.

AQ-SC9 The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with the conditions of certification herein. The Quarterly Operation Report will specifically note or highlight incidences of noncompliance.

Verification: The project owner shall submit the Quarterly Operation Reports to the CPM and APCO no later than 30 days following the end of each calendar quarter.

DISTRICT CONDITIONS OF CERTIFICATION

Conditions Applicable to Hidden Hills Solar 1 Power Plant (GBUAPCD ATC Number 1604-00-11) and Hidden Hills Solar 2 Power Plant (GBUAPCD 1605-00-11) (identical conditions, only equipment ID numbers differ).

References below to the "CPM" mean the Energy Commission's Compliance Program Manger.

GENERAL CONDITIONS

AQ-1 Facility Startup

The permittee shall notify the District in writing when construction is complete and the equipment is ready for commissioning operations. Operation of this equipment shall be conducted in accordance with all data and specifications submitted with the application under which this ATC is issued unless otherwise noted. Notification shall be given to the District office by email, Postal Service delivery or telephone facsimile transmission at least 72 hours prior to equipment start-up. Operation of this equipment without a written Permit to Operate is a violation of District Rule 200 B, and can result in civil and criminal penalties under California Health & Safety Code (H&SC) § 42400.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or the CPM.

AQ-2 Commissioning Period under Temporary Permit to Operate:

Following a District inspection verifying that the facility is constructed in a manner consistent with the specifications in the application and with this Authority to Construct, a temporary Permit to Operate (TPO) shall be issued. The TPO shall be valid for the duration of the commissioning period defined below and until a Permit to Operate is issued or denied.

A. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the boilers and associated control systems.

B. The commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a boiler is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial source testing, completed final plant tuning, and is available for commercial operation.

C. During the commissioning period, the owner or operator shall keep records of the natural gas fuel combusted in the boilers on hourly and daily basis. The natural gas fuel combusted during the commissioning period shall accrue towards the annual fuel use limit.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

AQ-3 Right-of-Entry

The "Right of Entry", as defined by California H&SC § 41510 of Division 26, shall apply at all times with respect to the equipment and the Control System. Representatives of the Great Basin Unified Air Pollution Control District shall be permitted to enter the facility to inspect and copy any record required to be kept under the terms of this permit. District staff shall also be permitted to inspect any equipment, work practices, air emission-related activity or method dictated by this permit. If deemed necessary by the District to verify compliance with these conditions, the permittee shall within 7 days notice be available to open any sample extraction port, or exhaust outlet for the purpose of conducting source tests or to collect samples. In enforcing the terms of this permit, any cost incurred in collecting samples, source testing and laboratory analysis fees shall be the responsibility of the project owner. [District Rules 210 and 302 Analysis Fee]

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

AQ-4 Copy of Permit Onsite

A copy of the permit shall be maintained readily available at all times on the operating premises. [District Rule 200.D]

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

AQ-5 Report Violation of Emission Standard

Any violation of any emission standard to which the stationary source is required to comply, as indicated by the records of the monitoring device, shall be reported by the operator of the source to the district within 96 hours after such occurrence. The district shall, in turn, report the violation to the state board within five working days after receiving the report of the violation from the operator. [Cal H&S § 42706]

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

AQ-6 Severability Clause

If any provision of this permit is found invalid, such finding shall not affect any remaining provisions. [District Rule 107]

<u>Verification:</u> During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

AQ-7 Right to Revise Permit

The provisions of this permit may be modified by the District if it determines the stipulated conditions are inadequate. [District Rule 210.C]

<u>Verification:</u> During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

AQ-8 Breakdown (or Emergency) Reporting Conditions

A breakdown condition means an unforeseeable failure or malfunction of: 1) any air pollution control equipment or related operating equipment which causes a violation of any emission limitation or restriction prescribed by this permit or District rules and regulations, or by State law, or 2) any in-stack continuous monitoring equipment.

A. The permittee shall comply with the breakdown requirements of District Rule 403 (Breakdown), which shall include notifying the Air Pollution Control Officer of a breakdown condition within an hour of detection, unless it can be demonstrated that a longer reporting period is necessary -- not to exceed two (2) days.

B. Notification shall identify the time, location, equipment involved, and to the extent possible the cause of the breakdown and steps taken to correct the breakdown condition.

C. Within one (1) week after the breakdown occurrence, the permittee shall submit a written report to the Air Pollution Control Officer which includes: date of correction of the breakdown, determination of the cause of the breakdown, corrective measures to prevent a recurrence, an estimate of the emissions caused by the breakdown condition, and pictures of the failed equipment, if available.

D. Breakdown conditions shall not persist longer than 24 hours or the end of the production run, whichever is sooner, except for continuous monitoring equipment, for which the period shall be ninety-six (96) hours, unless the permittee obtains an Emergency Variance pursuant to District Rule 617. [District Rule 403]

<u>Verification:</u> During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

FACILITY OPERATING CONDITIONS

AQ-9 Visible Emissions Opacity Limit

Visible emissions from any source shall not exceed a Ringelmann 1 (20% opacity) for a period or periods aggregating more than three minutes in any one hour. [District Rule 400]

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

AQ-10 Unit Emission Limits

To demonstrate consistency with the ambient air quality modeling and the screening health risk assessment provided in the application for certification to the California Energy Commission, the pound per hour equipment emission rate limits in Table 1 shall apply. Except during the commissioning period, startup/shutdown conditions and standby conditions, the pound per million Btu limits shall also apply. Compliance with these lb/MMBtu limits will also ensure compliance with the limits in the applicable New Source Performance Standards (NSPS).

Table 1: Criteria pollutant emission limits per unit in pounds per hour (pounds per million Btu)

Pollutant	Auxiliary Boiler	Nighttime Preservation Boiler	Emergency Backup Engine	Emergency Fire Pump Engine
NOx as NO_2	2.74 (0.0110)	0.17 (0.0110)	38.4	1.3
CO	4.55 (0.0183)	0.55 (0.0366)	20.8	1.15
VOC as CH_4	1.34 (0.0054)	0.08 (0.0053)	1.3	0.08
PM10/PM2.5	1.25 (N/A)	0.08 (N/A)	1.2	0.07
SO_2	0.52 (0.0021)	0.03 (0.0021)	0.04	0.003

Verification: The project owner shall submit to the CPM data showing compliance with the limits of this condition as part of the Quarterly Operation Report required under **AQ-SC9**.

AQ-11 Combined Plant-wide Daily Emission Limits

A. “Plant-wide” shall mean this Solar 1 Power Plant facility, GBUAPCD № 1604-00-11, plus the adjacent Solar 2 Power Plant and Common Area facilities (permitted separately, GBUAPCD № 1605-00-11 and 1606-00-11, respectively).

B. The total plant-wide combined emissions from the auxiliary and nighttime preservation boilers, emergency and fire pump engines shall not exceed the limits in Table 2.

Table 2: Criteria pollutant emission limits in pounds per day

Pollutant	All Fuel Burning Equipment
NOx as NO_2	116.0
CO	156.1
VOC as CH_4	37.8
$PM_{10}/PM_{2.5}$	21.3
SO_2	7.4

C. Compliance demonstration with these plant-wide limits shall entail the monitoring, recordkeeping and reporting requirements specified later in this permit.

D. Compliance with the NOx limit shall be demonstrated via the use of a plant-wide NOx Predictive Emission Monitoring System (PEMS), in accordance with condition of certification AQ-18, that totals both power plants' boiler emission rates.

Verification: The project owner shall submit a letter annually confirming compliance with this condition, to the CPM. During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

AQ-12 Boiler Fuel Use Limits

The total natural gas fuel consumption, expressed as heat input rates, shall not exceed 3,440 MMBtu/day or 746,400 MMBtu/year for combustion in the burners of all auxiliary and nighttime preservation boilers in the Solar 1 facility plus the adjacent Solar 2 facility (permitted separately, GBUAPCD №1605-05-11).

Verification: The project owner shall submit to the CPM the boiler fuel use data demonstrating compliance with this condition as part of the Quarterly Operation Report.

AQ-13 Toxic Hot Spots Program (AB 2588)

In lieu of an emissions inventory plan, the District accepts the screening health risk assessment provided in the Application for Certification to the California Energy Commission. The combined Solar 1 and Solar 2 facilities shall be categorized under AB 2588 as "Intermediate Level" and shall meet the reporting requirements under Section V of the Emission Inventory Criteria and Guidelines for the Air Toxics "Hot Spots" Program.

Verification: During site inspection, the project owner shall make all records and reports available to the District, ARB, U.S. EPA or CPM.

BOILER SPECIFICATIONS AND NSPS STANDARDS

AQ-14 Boiler Specifications

Each 249 MMBtu/hr auxiliary boiler and each 15 MMBtu/hr nighttime preservation boiler shall be equipped with low-NOx burners, 9 ppmvd NOx at 3% O_2 or less at loads exceeding 25% maximum continuous rating (MCR), and flue gas recirculation (FGR). The boilers shall meet all specifications stated in the permit application, including stack dimensions and pollutant emission rates.

Verification: As part of the Annual Compliance Report (**COMPLIANCE-7**), the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-15 New Source Performance Standards (NSPS) for Auxiliary Boiler

Each auxiliary boiler shall comply with the requirements of 40 CFR 60 Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units. The boiler shall meet the following emission standards at all times except during periods of startup, shutdown, or malfunction:

- NOx: 0.20 lb/MMBtu (30-day average) [40 CFR §60.44b(a)]
- SO_2: 0.20 lb/MMBtu [40 CFR §60.42b(k)]

Verification: The project owner shall complete and submit to the CPM a compliance plan that provides a list of the 40 CFR 60 Subpart Db plans, tests, and recordkeeping requirements and their compliance schedule, dates as applicable for the HHSEGS Boilers 1, and 2 at least 30 days prior to first fire of the boilers or earlier as necessary for compliance with Subpart Db.

AQ-16 New Source Performance Standards (NSPS) for Nighttime Preservation Boiler

Each nighttime preservation boiler shall comply with the requirements of 40 CFR 60 Subpart Dc – NSPS for Small Industrial-Commercial-Institutional Steam Generating Units. The SO_2 emission limit in this subpart does not apply because the unit is rated below 30 MMBtu/hr.

Verification: The project owner shall complete and submit to the CPM a compliance plan that provides a list of the 40 CFR 60 Subpart Dc plans, tests, and recordkeeping requirements and their compliance schedule dates as applicable for the boilers on HHSEGS Solar Plant 1, and HHSEGS Solar Plant 2 at least 30 days prior to first fire of the boilers or earlier as necessary for compliance with Subpart Dc.

BOILER MONITORING CONDITIONS

AQ-17 Fuel Type and Flow Monitoring

A. The burners for the auxiliary and nighttime preservation boilers shall be fueled with natural gas that meets the standards of the California Public Utilities Commission (CPUC).

B. Each boiler shall be equipped with a continuous flow monitoring system to measure and record fuel consumption in million standard cubic feet per hour (MMscf/hr).

Verification: As part of the Annual Compliance Report (**COMPLIANCE-7**), the project owner shall include proof that only pipeline quality natural gas that meets Public Utilities Commission standards are used for the boilers. The Annual Compliance Report shall also report fuel used in each boiler.

AQ-18 Boiler Predictive NOx Emission Rate Monitoring Plan

A. As an element of the PEMS required by condition of certification **AQ-11.D**, the permittee shall estimate the auxiliary boiler emissions by continuously monitoring parameters indicative of emissions and maintaining records of the amount of natural gas combusted. The permittee shall monitor the auxiliary boiler operating conditions and predict NOx emission rates as specified in a plan that shall:

(1) Be submitted to the District within 360 days of initial startup in accordance with 40 CFR Subpart Db §60.49b(c) and §60.49b(g);

(2) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NOx emission rates (i.e., lb/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas O_2 level);

(3) Include the data and information that the permittee used to identify the relationship between NOx emission rates and these operating conditions; and

(4) Identify how these operating conditions, including steam generating unit load, will be monitored on an hourly basis by the permittee during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the permittee under 40 CFR §60.49b(g). [40 CFR Subpart Db §60.48b(d)]

B. If the permittee elects to estimate NOx emissions from the Nighttime Preservation Boilers using the pound per hour emission limit in Table 1, then the Plan may require continuous monitoring of only operating hours and fuel use for the Nighttime Preservation Boilers.

Verification: This initial plan shall be submitted to the district for approval, and the CPM for review, within 360 days of the initial startup. Any proposed changes to a district-approved plan shall include subsequent test results, operating parameters, analysis, and any other pertinent information to support the proposed changes. The district must approve any emissions estimation plan or revision for estimated NOx emissions to be considered valid.

BOILER TESTING CONDITIONS

AQ-19 Initial Boiler Testing

Initial performance testing shall be completed on each auxiliary and nighttime preservation boiler to demonstrate compliance with the emission limits specified in condition of certification **AQ-10** at each boiler's maximum achievable production rate.

A. The initial performance test is to be scheduled within 60 days after achieving the maximum continuous rating (MCR) at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. [§60.45b and 60.46b]

B. The permittee shall provide safe and accessible sampling ports that comply with California Industrial Safety Orders and Uniform Building Code and 40 CFR 60, Appendix A, Test Method 1.

C. A test protocol must be submitted to the Air Pollution Control District not later than 30 days before the proposed test date. This test protocol shall be approved by the District before testing begins and shall include the following, or other District-approved methods:

- PM10 emissions: EPA Method 5, Methods 201/202 or ARB Method 5
- NOx emissions: EPA Method 7, 7A, 7E
- SO_2 emissions: EPA Method 6, 6A, 6B or 6C
- CO emissions: EPA Method 10
- VOC emissions: EPA Method 25A

D. A copy of the test results shall be submitted to the District within 60 days following test completion. [District Rule 200.C, and Cal H&S Code § 44340]

Verification: The project owner shall notify the District and the CPM within thirty (30) working days before the execution of the compliance test required in this condition. The test results shall be submitted to the district and to the CPM within 60 days of the date of the tests.

DIESEL BACKUP GENERATOR AND FIRE PUMP ENGINE CONDITIONS

AQ-20 Emergency Backup Generator Engine

Each emergency backup generator shall be powered by a Tier 2, diesel-fueled, Caterpillar 3516C SCAC, 3,633 hp at 1,800 rpm, EPA Family ACPXL78.1T2E, ARB Executive Order U-R-001-0398-1, or an equivalent ARB-certified engine that meets the current EPA Tier standards for the given power range.

Verification: The project owner shall submit the emergency generator specifications to the CPM at least 30 days prior to purchasing the engines for review and approval.

AQ-21 Emergency Fire Pump Engine

Each emergency fire pump shall be powered by a Tier 3, diesel-fueled, Cummins CFP7E-F30, 200 hp at 2,100 rpm, EPA Family ACEXL0409AAB, ARB Executive Order U-R-002-0516, or an equivalent ARB-certified engine that meets the current EPA Tier standards for the given power range.

Verification: The project owner shall submit the emergency engine specifications to the CPM at least 30 days prior to purchasing the engines for review and approval.

AQ-22 Airborne Toxics Control Measure (also applies to Hidden Hills Common Area)
The permittee shall operate the diesel emergency backup generator and fire pump engines in compliance with the California Code of Regulations, Title 17 (17 CCR) § 93115.

Verification: The project owner shall submit the engine specifications at least 30 days prior to purchasing the engines for review and approval demonstrating that the engines meet NSPS and ARB ATCM emission limit requirements at the time of engine purchase.

AQ-23 Particulate Matter Limit (also applies to Hidden Hills Common Area)
Each emergency engine shall not discharge into the atmosphere particulate matter in excess of 0.3 grains per dry standard cubic foot of exhaust gas. [Rule 404-A].

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the CPM.

AQ-24 ARB Diesel Fuel (also applies to Hidden Hills Common Area)
Each engine shall be fueled with ARB diesel fuel with 15 parts-per-million sulfur content by weight or less, or an alternative diesel fuel that meets the requirements of the Standard of Motor Vehicle Fuel found in Title 13, CCR (13 CCR) § 2281. The amount of sulfur dioxide exhausted to the atmosphere shall not exceed 0.2% by volume. The permittee shall keep records of the composition of purchased fuel. [District Rules 210 and 416; 17 CCR § 93115.5(a)(1)]

Verification: During site inspection, the project owner shall make all records and reports available to the district, ARB, U.S. EPA or CPM.

AQ-25 Hour Meter Required (also applies to Hidden Hills Common Area)
A non-resettable totalizer elapsed time meter shall be installed and maintained on each engine to indicate the cumulative hours of engine operation. [District Rule 210.A, 17 CCR § 93115].

Verification: At least thirty (30) days prior to the installation of the engine, the project owner shall provide the district and the CPM the specification of the hour timer.

AQ-26 Non-Emergency Use Limitation (also applies to Hidden Hills Common Area)

A. Each emergency backup generator engine shall be allowed to operate up to 50 hours per year for maintenance and testing purposes. Operation of the engine beyond the 50 hours shall be allowed only by the events as defined in condition of certification **AQ-27** for what constitutes emergency use. [District Rule 210.A, 17 CCR § 93115.6(a)(3)(A)].

B. Each fire pump engine shall not operate more than the number of hours (up to 30 hours per year) necessary to comply with the testing requirements of the National Fire Protection Association (NFPA). [District Rule 210.A, 17 CCR § 93115.6(a)(4)(A)].

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the district, ARB, and the CPM.

AQ-27 What Constitutes Emergency Use (also applies to Hidden Hills Common Area)

Emergency use of the engines is not limited and is defined in 17 CCR § 93115 as providing electrical power or mechanical work during any of the following events and subject to the following conditions that:

A. the failure or loss of all or part of normal electrical power service or normal natural gas supply to the facility:

(1) which is caused by any reason other than the enforcement of a contractual obligation the permittee has with a third party or any other party; and

(2) which is demonstrated by the permittee to the district APCO's satisfaction to have been beyond the reasonable control of the owner or operator;

B. the failure of a facility's internal power distribution system:

(1) which is caused by any reason other than the enforcement of a contractual obligation the permittee has with a third party or any other party; and

(2) which is demonstrated by the permittee to the district APCO's satisfaction to have been beyond the reasonable control of the owner or operator.

C. the pumping of water for fire suppression or protection;

D. the pumping of water to maintain pressure in the water distribution system for the following reasons:

(1) a pipe break that substantially reduced water pressure; or

(2) high demand on the water supply system due to high use of water for fire suppression; or

(3) the breakdown of electric-powered pumping equipment at sewage treatment facilities or water delivery facilities.

[District Rule 210.A, 17 CCR § 93115].

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the district, ARB, and the CPM.

AQ-28 Required Records for Emergency Engines (also applies to Hidden Hills Common Area)

The permittee shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

A. emergency use hours of operation;

B. maintenance and testing hours of operation;

   a. hours of operation for emission testing to show compliance with the applicable standard;

C. initial start-up testing hours;

D. hours of operation for all uses other than those specified above; and

E. the fuel used.

   (1) For engines operated exclusively on ARB Diesel Fuel, the owner or operator shall document the use of ARB Diesel Fuel through the retention of fuel purchase records indicating that the only fuel purchased for supply to an emergency standby engine was ARB Diesel Fuel; or

   (2) For engines operated on any fuel other than ARB Diesel Fuel, fuel records demonstrating that the only fuel purchased and added to an emergency standby engine or engines, or to any fuel tank directly attached to an emergency standby engine or engines, meets the requirements of section 93115.5(b).

[District Rule 210.A, 17 CCR § 93115.10(g)(1)].

Verification: The project owner shall submit records required by this condition that demonstrating compliance with the sulfur content and engine use limitations of conditions **AQ-24** and **AQ-27** in the Annual Compliance Report, including a photograph showing the annual reading of engine hours. The project owner shall make the site available for inspection of records by representatives of the district, ARB, and the CPM.

AQ-29 Record Retention (also applies to Hidden Hills Common Area)
Log entries shall be retained for a minimum of 36 months from the date of entry. Log entries made within 24 months of the most recent entry shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request. Log entries made from 25 to 36 months from most recent entry shall be made available to District staff within 5 working days from request. [Rule 210.A, 17 CCR § 93115.10(g)(2)].

Verification: The project owner shall submit records required by this condition that demonstrating compliance with the sulfur content and engine use limitations of conditions **AQ-24,** and **AQ-27** in the Annual Compliance Report, including a photograph showing the annual reading of engine hours. The project owner shall make the site available for inspection of records by representatives of the district, ARB, and the CPM.

PARTICULATE MATTER MITIGATION CONDITIONS

AQ-30 Fugitive Dust Mitigation

The permittee shall take reasonable precautions during construction activities to prevent visible particulate matter from being airborne, under normal wind conditions, beyond the HHSEGS property line, in accordance with the requirements for dust control in Rule 401.A. The District deems the California Energy Commission (CEC) staff conditions of certification (HHSEGS) **AQ-SC1** through **AQ-SC5** for construction and operation mitigation methods to be reasonable precautions under Rule 401. The permittee shall submit the Air Quality Construction Mitigation Plan, required by **AQ-SC2** to the District after its approval by the CEC.

Verification: The permittee shall submit the Air Quality Construction Mitigation Plan, required by **AQ-SC2** to the District after its approval by the CEC. The permittee shall make available to the District, upon request, copies of the CEC-required MCR containing documentation of the actions taken to comply with these conditions.

FACILITY RECORDKEEPING & REPORTING CONDITIONS

AQ-31 Natural Gas Heat Input Records

Records for demonstrating compliance with the plant-wide natural gas combustion heat input, required by condition of certification **AQ-12**, shall be presented in MMBtu/day, MMBtu/month and MMBtu per rolling 12-month period.

Verification: The project owner shall submit to the CPM the boiler fuel use data demonstrating compliance with this condition as part of the Quarterly Operation Report.

AQ-32 Plant-wide Emission Records

Emission records for the plant-wide NOx PEMS, required by condition of certification AQ-11, shall be presented in pounds per hour (lb/hr), pounds per day (lb/day) and pounds per million Btu (lb/MMBtu) for each individual boiler in the Solar 1 and Solar 2 facilities. The sum total of NOx for all boilers shall be presented in pounds per day (lb/day) for each calendar day, midnight to midnight. Data obtained to estimate boiler NOx emissions shall be presented as specified in the plant-wide NOx PEMS plan required by condition of certification AQ-18.

Verification: The project owner shall submit to the CPM the boiler fuel use data demonstrating compliance with this condition as part of the Quarterly Operation Report.

AQ-33 Monitoring Record Retention

Required recordkeeping information shall be retained by the permittee in a form suitable for inspection for a period of at least two (2) years from the end of the calendar year of the journal entry. [Rule 206.B, Cal H&S Code § 42705]

Verification: The project owner shall submit records required by this condition that demonstrating compliance with the sulfur content and engine use limitations of conditions **AQ-24,** and **AQ-27** in the Annual Compliance Report, including a photograph showing the annual reading of engine hours. The project owner shall make the site available for inspection of records by representatives of the district, ARB, and the CPM.

AQ-34 Reporting of Monitoring Records

All monitoring records shall be made immediately available to the District staff upon request.

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the district, ARB, and the CPM.

Conditions Applicable to Hidden Hills Common Area (GBUAPCD ATC Number 1606-00-11)

GENERAL CONDITIONS

General conditions **AQ-1** and **AQ-3** to **AQ-8** for Hidden Hills Solar 1 Power Plant and Solar 2 Power Plant are also applicable for the Common Area.

FACILITY OPERATING CONDITIONS

AQ-35 Unit Emission Limits

To demonstrate consistency with the ambient air quality modeling and the screening health risk assessment provided in the Application for Certification to the California Energy Commission, the pound per hour equipment emission rate limits in Table 1 shall apply.

Table 1: Common Area Emission Limits in pounds per hour

Pollutant	Emergency Backup Engines	Emergency Fire Pump Engines
NOx as NO_2	2.6	1.3
CO	2.28	1.15
VOC as CH_4	0.15	0.08
$PM_{10}/PM_{2.5}$	0.13	0.07
SO_2	0.004	0.003

Verification: The project owner shall submit to the CPM data showing compliance with the limits of this condition as part of the Quarterly Operation Report

DIESEL BACKUP GENERATOR AND FIRE PUMP ENGINE CONDITIONS

AQ-36 Visible Emissions Opacity Limit

Visible emissions from each engine shall not exceed a Ringelmann 1 (20% opacity) for a period or periods aggregating more than three minutes in any one hour. [District Rule 400]

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the district, ARB, and the CPM.

AQ-37 Emergency Backup Generator Engine

The emergency backup generator (Unit EG1C) shall be powered by a Tier 3, diesel-fueled, Caterpillar C9 ATAAC, 398 hp at 1,800 rpm, EPA Family ACPXL08.8ESX, ARB Executive Order U-R-001-0373, or an equivalent ARB-certified engine that meets the current EPA Tier standards for the given power range.

Verification: During site inspection, the project owner shall make all records and reports available to the district, ARB, EPA or CPM.

AQ-38 Emergency Fire Pump Engine

The emergency fire pump (Unit FP1C) shall be powered by a Tier 3, diesel-fueled, Cummins CFP7E-F30, 200 hp at 2,100 rpm, EPA Family ACEXL0409AAB, ARB Executive Order U-R-002-0516, or an equivalent ARB-certified engine that meets the current EPA Tier standards for the given power range.

Verification: During site inspection, the project owner shall make all records and reports available to the district, ARB, EPA or CPM.

Conditions **AQ-22** to **AQ-29** also apply to the Hidden Hills Common Area.

ACRONYMS

AAQS	Ambient Air Quality Standard
ACC	Air Cooled Condenser
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMD	Air Quality Management District
ARB	California Air Resources Board
ATC	Authority to Construct
ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
bhp	brake horsepower
BRW	Basin Range and Watch
Btu	British thermal unit
CAA	Clean Air Act (Federal)
CAAQS	California Ambient Air Quality Standard
CCR	California Code of Regulations
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPM	(CEC) Compliance Project Manager
DOC	Determination of Compliance
dscf	dry standard cubic feet
EIR	Environmental Impact Report
ERC	Emission Reduction Credit
FDOC	Final Determination Of Compliance
FSA	Final Staff Assessment (this document)
GBUAPCD	Great Basin Unified Air Pollution Control District
GBVAB	Great Basin Valleys Air Basin
GHG	Greenhouse Gas
gr	Grains (1 gr ≅ 0.0648 grams, 7000 gr = 1 pound)
hp	horsepower
H_2S	Hydrogen Sulfide
HSC	Health and Safety Code

HHSEGS	Hidden Hills Solar Electric Generating System (proposed project)
lbs	Pounds
LORS	Laws, Ordinances, Regulations and Standards
MCR	Monthly Compliance Report
mg/m^3	milligrams per cubic meter
MMBtu	Million British thermal units
MW	Megawatts (1,000,000 Watts)
NAAQS	National Ambient Air Quality Standard
NH_3	Ammonia
NMHC	Non-Methane Hydrocarbons
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
OLM	Ozone Limiting Method
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSA	Preliminary Staff Assessment
PTO	Permit to Operate
PVMRM	Plume Volume Molar Ratio Method
scf	Standard Cubic Feet
SO_2	Sulfur Dioxide
SO_3	Sulfate
SOx	Oxides of Sulfur
SRSG	Solar Receiver Steam Generator
STG	Steam Turbine Generator

U.S. EPA	United States Environmental Protection Agency
$\mu g/m^3$	Microgram per cubic meter
VOC	Volatile Organic Compounds

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AIR QUALITY APPENDIX AIR-1
GREENHOUSE GAS EMISSIONS

Jacquelyn Leyva and David Vidaver

SUMMARY AND CONCLUSIONS

The Hidden Hills Solar Electric Generating System (HHSEGS) project is a proposed renewable project addition to the state's electricity system. If built, it would significantly contribute to the State of California's goal of having one-third of its electrical energy produced by renewable power plants by the year 2020. HHSEGS would be a concentrating solar power plant that would comprise fields of heliostat mirror arrays focusing solar energy on the solar receiver located on centralized power towers. As a solar project, it would emit considerably fewer greenhouse gases (GHG) than existing power plants and most other generation technologies, and thus would contribute to continued reduction of the annual average GHG emission rates for both California and the western United States. While HHSEGS would emit some GHG emissions, HHSEGS's contribution to the system build-out of renewable resources in California would result in a net cumulative reduction of energy consumption and GHG emissions from new and existing fossil resources.

Electricity is produced by operation of inter-connected generation resources. Operation of any one power plant, like HHSEGS, affects all other power plants in the inter-connected system. The operation of the HHSEGS would affect the overall electricity system operation and GHG emissions in several ways:

- HHSEGS would displace higher GHG-emitting electricity generation. Because the project's GHG emissions per megawatt-hour (MWh) would be largely based upon renewable solar generation, GHG emissions would be much lower than power plants that the project would displace even with use of natural gas in the auxiliary boilers. Therefore, the addition of the HHSEGS would contribute to a reduction of California and overall Western Electricity Coordinating Council system GHG[10] emissions and GHG emission rate average and would be part of a programmatic approach to meeting GHG emissions reduction goals.
- HHSEGS would facilitate to some degree the replacement out-of-state high-GHG-emitting (e.g., coal) electricity generation that must be phased out in conformance with the State's Emissions Performance Standard.
- HHSEGS could facilitate to some extent the replacement of generation provided by aging power plants and those that use once-through cooling (OTC).

These system effects would result in a net reduction in GHG emissions across the electricity system providing energy and capacity to California. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions from power

[10] Fuel-use closely correlates to the efficiency of and carbon dioxide (CO_2) emissions even from renewable power plants. Since CO_2 emissions from fuel combustion dominate greenhouse gas (GHG) emissions from power plants, the terms CO_2 and GHG are used interchangeably in this section.

plants, would not worsen current conditions, and would not result in impacts that are cumulatively significant.

Staff concludes that the short-term, minor emissions of greenhouse gases during construction that are necessary to create this new, very low GHG-emitting renewable power generating facility would be reduced by “best practices” and would, therefore, would not be a significant impact.

The Hidden Hills Solar Electric Generating System project, as a solar project with a nightly shutdown, would operate significantly less than a 60 percent capacity factor and therefore would not be subject to the requirements of SB 1368 (Greenhouse Gases Emission Performance Standard; Title 20, California Code of Regulations, section 2900 et. seq.). However, the HHSEGS would easily comply with the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard.

AIR QUALITY GHG ANALYSIS - Jacquelyn Leyva Record

INTRODUCTION

The generation of electricity using fossil fuels, even in an auxiliary boiler or back-up generator at a thermal solar plant, produces greenhouse gas emissions in addition to the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. California is actively pursuing policies to reduce GHG emissions that include adding non-GHG emitting renewable generation resources to the system. The greenhouse gases are carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFC), and perflurocarbons (PFC). CO_2 emissions are far and away the most common of these emissions; as a result, even though the other GHGs may have a greater impact on climate change on a per-unit basis due to their greater global warming potential, GHG emissions are often “normalized” in terms of metric tons of CO_2-equivalent (MTCO2E) for simplicity. Global warming potential is a relative measure, compared to carbon dioxide, of a compound’s ability to warm the planet, taking into account each compound’s expected residence time in the atmosphere.

GHG emissions are not included in the class of pollutants traditionally called “criteria pollutants.” Since the impact of the GHG emissions from a power plant’s operation has global rather than local effects, those impacts should be assessed not only by analysis of the plant’s emissions, but also in the context of the operation of the entire electricity system of which the plant is an integrated part. Furthermore, the impact of the GHG emissions from a power plant’s operation should be analyzed in the context of applicable GHG laws and policies, especially AB 32, California’s Global Warming Solutions Act of 2006.

The state has demonstrated a clear willingness to address global climate change though research, adaptation[11], and GHG emissions reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG

[11] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state’s climate (for example, changing rainfall patterns).

emissions related to electricity generation (see “**Electricity System GHG Impacts**” below) and describes the applicable GHG policies and programs.

In December 2009, the U.S. Environmental Protection Agency (EPA) declared that greenhouse gases (GHGs) threaten the public health and welfare of the American people (the so-called “endangerment finding”). Regulating GHGs at the federal level is required by Prevention of Significant Deterioration Program (PSD) for sources that exceed 100,000 tons per year of carbon dioxide-equivalent emissions. Additionally, Federal rules that became effective December 29, 2009 (40 CFR 98) require federal reporting of GHGs. As federal rulemaking evolves, staff at this time focuses on analyzing the ability of the project to comply with existing federal- and state-level policies and programs for GHGs.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

The following federal, state, and local laws and policies in **Greenhouse Gas Table 1** pertain to the control and mitigation of greenhouse gas emissions applicable to power plants. Staff’s analysis examines the project’s compliance with these requirements.

GLOBAL CLIMATE CHANGE AND CALIFORNIA

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps significantly) to that change. Man-made emissions of greenhouse gases, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature finds that “[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California” (Cal. Health & Safety Code, sec. 38500, division 25.5, part 1).

In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p. 5). In 2003, the Energy Commission recommended that the state require reporting of greenhouse gases or global climate change[12] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the California Air Resources Board (ARB) to adopt standards to reduce statewide GHG emissions to GHG emissions levels that existed in 1990, with such reductions to be achieved by 2020. To achieve this, ARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-effective GHG emission reductions to meet this requirement. Executive Order S-3-05 also requires ARB to plan for further GHG emissions reductions to achieve an 80 percent reduction from 1990 GHG emissions by the year 2050.

[12] Global climate change is the result of greenhouse gases, or air emissions with global warming potentials, affecting the global energy balance and thereby the global climate of the planet. The terms greenhouse gases (GHGs) and global climate change (GCC) gases are used interchangeably.

The ARB adopted early action GHG reduction measures in October 2007, adopted mandatory reporting requirements and the 2020 statewide target in December 2007, and adopted a statewide scoping plan in December 2008 to identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. ARB adopted regulations implementing cap-and-trade regulations on December 22, 2011 and ARB staff continues to develop and implement regulations to refine key elements of the GHG reduction measures to improve their linkage with other GHG reduction programs. Federal and state mandatory reporting and state cap-and-trade requirements all apply to this project.

Greenhouse Gas Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule "tailors" GHG emissions to PSD and Title V permitting applicability criteria.
40 Code of Federal Regulations (CFR) Parts 51 and 52	A new stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) is considered to be a major stationary source subject to Prevention of Significant Determination (PSD) requirements. This project would not trigger this 100,000 TPY PSD threshold.
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year. This requirement is triggered by this project.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards that will reduce GHG emission to 1990 levels by 2020. Electricity production facilities are regulated by the ARB. A cap-and-trade program became active in January 2012, with enforcement to begin January 2013. Cap-and-trade is expected to achieve approximately 20 percent of the GHG reductions expected under AB 32 by 2020.
California Code of Regulations, Title 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
California Code of Regulations, Title 17, Subchapter 10, Article 5, sections 95800 to 96023	These ARB regulations implement mandatory GHG cap-and-trade requirements for "covered entities," which include power plants which emit more than 25,000 metric tons of carbon dioxide equivalent emissions per calendar year. Enforcement begins January 2013.
Title 20, California Code of Regulations, section 2900 et seq.	These regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 MTCO2/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO2/MWh).

The California Climate Action Team produced a report to the Governor (CalEPA 2006) which included many examples of strategies that the state could pursue to reduce GHG emissions in California, in addition to several strategies that had been recommended by the Energy Commission and the Public Utilities Commission. Their third biennial report, published in December 2010 and required by Executive Order S-3-05, is the most recent report addressing actions that California could take to reduce GHG emissions (CalEPA 2010). The scoping plan approved by ARB in December 2008 builds upon the overall climate change policies of the Climate Action Team reports and includes recommended strategies to achieve the goals for 2020 and beyond. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a 33% Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade program that includes the electricity sector (ARB 2008). Mandatory compliance with cap-and-trade requirements commenced on January 1, 2012, although enforcement was delayed until January 2013. Senate Bill 2 (Simitian, Chapter 1, Statutes of 2011-12) expresses the intent of the California Legislature to have 33 percent of California's electricity supplied by renewable sources by 2020 and the Hidden Hills Project would contribute to this goal.

It is likely that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the greatest GHG reduction for the least cost). For example, ARB proposes a 40 percent reduction in GHG emissions from the electricity sector even though that sector currently only produces about 25 percent of the state's GHG emissions.

SB 1368,[13] enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to that bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission Performance Standard (EPS) of 0.5 metric tonnes CO_2 per megawatt-hour[14] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California.[15] If a project, instate or out of state, plans to sell base load electricity to California utilities, those utilities will have to demonstrate that the project meets the EPS. *Base load* units are defined as units that are expected to operate at a capacity factor higher than 60 percent. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. This determination is based on capacity factors, heat rates, and corresponding emissions rates that reflect the *expected* operations of the power plant and not on full load heat rates [Chapter 11, Article 1 §2903(a)]. At the January 12, 2012 Business Meeting, the Energy Commission opened an Order Instituting Rulemaking (12-OIR-1) to consider revisions to the EPS.

[13] Public Utilities Code § 8340 et seq.

[14] The Emission Performance Standard only applies to carbon dioxide and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[15] See Rule at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

In addition to these programs, California is involved in the Western Climate Initiative (WCI), a multi-state and international effort to establish a cap-and-trade market to reduce greenhouse gas emissions in the Western United States and the Western Electricity Coordinating Council (WECC). WCI created a special entity, WCI, Inc. to assist jurisdictions that are moving ahead with cap-and-trade programs. The initial participants are California and the Canadian province of Quebec. Two other Canadian provinces may join in the near future.

Each participating entity is developing their own cap-and-trade program to reduce greenhouse gas pollution, using their own authorities, laws and regulations. These programs will be linked in a larger market if each participating organization finds that such joining of programs creates synergy and can be done without adversely impacting their own system.

WCI timelines are similar to those of AB 32, with full roll-out beginning in 2012. And, as with AB 32, the electricity sector has been a major focus of attention of this group. ARB continues to refine AB32 regulations to mesh California requirements with those of the WCI to minimize leakage of GHG emissions from one geographic area to another. For example, they held a staff workshop on April 9, 2012 to discuss draft amendments to California's cap-and-trade program to better link these two efforts. None of the proposed amendments would change GHG requirements for HHSEGS.

SB1018 (Unfinished Business, Senate Budget and Fiscal Review Committee, for purposes of implementing the Budget Act of 2012) establishes new legislative oversight and controls over the Air Resources Board including: the creation of a separate expenditure fund for proceeds from the auction or sale of allowances pursuant to the market-based compliance mechanism (their cap-and-trade program); the establishment of a separate Cost of Implementation Fee account for oversight and tracking of funds; oversight of actions taken on behalf of the State of California related to market-based compliance and auctions, specific to the Western Climate Initiative and Western Climate Initiative, Incorporated; and provides for return of certain funds to ratepayers of Investor Owned Utilities from funds related to the auction or sale of allowances.

If built, HHSEGS would be required to participate in California's greenhouse gas cap-and-trade program. This cap-and-trade program is part of a broad effort by the State of California to reduce GHG emissions as required by AB32, which is being implemented by ARB. As currently proposed, market participants such as HHSEGS would be required to report their GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing allowances from the capped market and offsets from outside the AB32 program. As new participants enter the market, and as the market cap is ratcheted down over time, GHG emission allowance and offset prices will increase, encouraging innovation by market participants to reduce their GHG emissions. Thus, HHSEGS, as a GHG cap-and-trade participant, would be consistent with California's landmark AB 32 Program, which is a statewide program coordinated with a region wide WCI program to reduce California's GHG emissions to 1990 levels by 2020.

ELECTRICITY AND GREENHOUSE GAS EMISSIONS

Electricity use can be as simple as turning on a switch to operate a light or fan. The system to deliver the adequate and reliable electricity supply is complex and variable. But it operates as an integrated whole to meet demand, such that the dispatch of a new source of generation unavoidably curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[16] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

Hidden Hills Project GHG Emissions

Project Construction

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. Construction of the HHSEGS project would involve 29 months of activity (not including start-up or commissioning). The project owner provided a GHG emission estimate for the entirety of the construction phase. Construction equipment would be powered with newer, higher air quality-tiered (thus, lower emitting) diesel powered equipment and "best practices" would also be incorporated to minimize criteria pollutant emissions. These mitigation measures are described in the air quality section and would also minimize carbon dioxide emissions because they would inherently require newer engine models. The GHG emissions estimate, presented below in **Greenhouse Gas Table 2**, includes the total emissions for the 29 months of construction activity in terms of CO_2-equivalent. Construction period GHG emissions average 4,175 MTCO2E per

Greenhouse Gas Table 2
HHSEGS, Estimated Potential Construction Greenhouse Gas Emissions

Construction Source [a]	Construction-Phase GHG Emissions over 29 months (MTCO2E) [b]
On-Site Construction Equipment	7,781
Off-Site Worker Travel, Truck Deliveries	2,308
Construction Total	**10,089**

Source: Table 5.1-32R (CH2 2012p)

Notes:
a. Includes emissions from workers commuting to work site.
b. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.

[16] See CEC 2009b, page 95.

year, compared to annual operating emissions of 61,628 MTCO2E with mirror washing or 40,481 MTCO2E excluding mirror washing. Operating emissions are described more fully below.

Project Operations

The proposed HHSEGS would be a nominal 500-megawatt (MW) solar power tower electrical generating facility located in Inyo County, comprised of two 250 MW units. The primary sources that would cause GHG emissions would be from power block maintenance activities, including mirror cleaning and minimal undesired vegetation removal, weekly testing of the emergency generator and firewater pump, daily operation of each boiler (five hours per day of operation plus additional hours for startup of each auxiliary boiler and twelve to sixteen hours per day of operation plus an hour for startup of each nighttime boiler) and employee commute trips.

Greenhouse Gas Table 3 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. Emissions are also converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials. Operating emissions are shown both with and without mirror washing.

Natural Carbon Uptake Reduction

This proposed project would cause the clearing of land and removal of vegetation, which would reduce the ongoing natural carbon uptake by vegetation. A study of the Mojave Desert indicated that the desert may uptake carbon in amounts as high as 100 grams per square meter per year (Wohlfahrt et. al. 2008). This would equate to a maximum reduction in carbon uptake, calculated as CO_2, of 1.48 MT of CO_2 per acre, per year, for areas with complete vegetation removal. For this 3,097 acre proposed project, which actually does not require the complete removal of vegetation over most of the project site, the maximum equivalent loss in carbon uptake assuming complete vegetation removal would be 4,582 MT of CO_2 per year, which would correspond to 0.003 MT of CO_2 per MWh generated. Therefore, the natural carbon uptake loss is negligible in comparison with the reduction in fossil fuel CO_2 emissions, which can range from 0.35 to 1.0 MT of CO_2 per MWh depending on the fuel and technology, that is enabled by this proposed project.[17] Given the current approach to minimizing vegetative removal, the impact would be less than significant.

Cumulative Impacts

Cumulative impacts are defined as “two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts” (CEQA Guidelines § 15355). “A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with

[17] *Wohlfahrt. et. al. 2008. Georg Wohlfahrt, Lynn F. Fenstermaker, and John A. Arnone III. Large annual net ecosystem CO_2 uptake of a Mojave Desert ecosystem. Global Change Biology, 2008 (14).*

other projects causing related impacts" (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects. This entire assessment is a cumulative impact assessment. The project alone would not be sufficient to measureable change global climate or global inventories. But the project would emit greenhouse gases and therefore has been analyzed as a potential cumulative impact in the context of existing electrical system, the GHG regulatory requirements and GHG energy policies.

COMPLIANCE WITH LORS

Although still being refined as discussed above, ARB's AB 32 regulations will address both the degree of electricity generation sector emissions reductions and the method by which those reductions will be achieved (e.g., through cap-and-trade or command-and-

Greenhouse Gas Table 3
HHSEGS, Estimated Potential Greenhouse Gas (GHG) Emissions

	Maximum Emissions, metric tonnes/yr				
Emitting Source	**CO_2**	**CH_4**	**N_2O**	**SF_6**	**CO_2-equivalent (MTCO2E[a] per year)**
Auxiliary Boilers	31,902	0.60	0.06	--	
Nighttime Preservation Boilers	7,672	0.14	0.01	--	
Power Block Emergency Generator	704	0.03	0.01	--	
Common Area Emergency Generator	41	1.7E-03	3.3E-04	--	
Power Block Fire Pump Engine	49	2.0E-03	4.0E-04	--	
Common Area Fire Pump Engine	24	9.9E-04	2.0E-04	--	
WSACs	0	0.00	0.00	--	
Equipment Leakage (SF_6)	--	--	--	2.0E-03[g]	
Total	40,392	0.77	0.081	2.0E-03	
Global warming potential multiplier	1x	21x	310x	23,900x	
Total Project GHG Emissions – MTCO2E [b]	**40,392**	**16.27**	**25.11**	**47.8**	**40,481**
Mirror washing activities FFT[c] (on-road vehicles)	19,670	17	50	--	19,737
Mirror washing activities NT[d] (off-road vehicles)	1,405	1	4	--	1,410
MTCO2	**61,467**			**MTCO2E [b]**	**61,628**
Facility MWh per year [e]	1,432,000				1,432,000
Facility CO_2 EPS (MTCO2/MWh)	0.043[f]			Facility GHG Performance (MTCO2E/MWh)	0.043[f]

Sources: Revised April 2012 boiler optimization filing App 5.1B and table 5.1B-13R (CH2 2012p)

Notes: a. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
b. Annualized basis uses the project owner's assumed maximum permitted operating basis.
c. Far from Tower (FFT)
d. Near Tower (NT)
e. Estimated Gross MWh
f. Value includes mirror washing
g. 2.0 E-03 is derived from 880.4 lbs of maximum onsite SF6, as shown in Hazardous Materials Table 5.5R-1 HHSEGS Chemical Inventory. Please see CEC 2012jj record of conversion.

control or both). However, the exact approach is still under refinement. That regulatory approach will address emissions not only from the newer, more efficient, and lower emitting facilities licensed by the Energy Commission, but also the older, higher-emitting facilities not subject to Energy Commission jurisdiction. This programmatic approach is expected to be more effective and less costly in reducing GHG emissions overall from the entire electricity sector to meet GHG emissions reduction goals.

ARB has adopted cap-and-trade requirements that went into effect in January 2012, although compliance is not required until January 2013. As ARB continues to codify improved GHG inventories and methods, it may become apparent that emission reductions from the generation sector are less cost-effective than other sectors, and that other sectors of sources can achieve reductions with relative ease and cost-effectiveness. However, all information to date suggests that the electricity sector would be affected at least in proportion to its contribution to GHG emissions, and moreso.

This project would be subject to ARB's mandatory reporting requirements and cap-and-trade requirements. How the project would comply with these ARB requirements is speculative at this time, but compliance would be mandatory. Compliance options for cap-and-trade would likely be a combination of purchased allowances and approved GHG emissions offsets, although GHG offsets are limited to no more than 8 percent of total obligations based upon mandatorily-reported GHG emissions. The project may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB. Similarly, this project would be subject to federal mandatory reporting of GHG emissions.

Reporting of GHG emissions would enable the project to demonstrate consistency with the policies described above and the regulations that ARB adopts and to provide information to demonstrate compliance with any additional, future AB 32 requirements if enacted in the next few years. Since this power project would be permitted for less than a 60 percent annual capacity factor, the project is not subject to the requirements of SB 1368 and the current Emission Performance Standard. However, the HHSEGS's GHG emission performance has been shown to be below the SB 1368 EPS level.

AVENAL PRECEDENT DECISION

The Energy Commission established a precedent in the Final Commission Decision for the Avenal Energy Project. This precedential decision requires all new fossil-fuel fired power plants certified by the Energy Commission to: (a) not increase the overall system heat rate for natural gas plants; (b) not interfere with generation from existing renewable facilities nor interfere with the integration of new renewable generation; and, (c) take into account these factors to ensure a reduction of systemwide GHG emissions and support the goals and policies of AB 32 (CEC 2009, page 111). This proposed, renewable energy project, with its minor amounts of fossil fuel use, would meet all of these conditions.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

The proposed HHSEGS promotes the state's efforts to move towards a high-renewable, low-GHG electricity system, and therefore reduces both the amount of natural gas used by electricity generation and greenhouse gas emissions. It does this in several ways:

- California's Energy Action Plan Loading Order specifies that electrical energy demand be met first by energy efficiency and demand response, followed by employing renewable energy such as would be provided by HHSEGS.

- The energy produced by the HHSEGS would displace energy from higher GHG-emitting coal- and gas-fired generation resources, lowering the GHG emissions from the western United States, the relevant geographic area for the discussion of GHG emissions from electricity generation.

- The dependable capacity provided by the HHSEGS would facilitate the retirement/divestiture of resources that cannot meet the Emissions Performance Standard or are adversely affected by the SWRCB's policy on once-through cooling (OTC).

- Finally, while the HHSEGS combusts natural gas in onsite boilers for the purposes of improving plants efficiency by facilitating the startup of the solar boiler system and to initiate and sustain output during periods of low solar irradiance, the latter displaces higher-emission generation. In addition, HHSEGS reduces the need for energy and ancillary services from natural gas-fired resources, potentially obviating the need for their construction/operation.

California's Energy Action Plan Loading Order

In 2003, the three key energy agencies in California – the California Energy Commission (Energy Commission), the California Power Authority (CPA), and the California Public Utilities Commission (CPUC) – came together in a spirit of unprecedented cooperation to adopt an "Energy Action Plan" (EAP) that listed joint goals for California's energy future and set forth a commitment to achieve these goals through specific actions. The EAP is a living document meant to change with time, experience, and need. In 2005 the CPUC and the Energy Commission jointly prepared an Energy Action Plan II to identify further actions necessary to meet California's future energy needs (CEC 2005).

The EAP's overarching goal is for California's energy to be adequate, affordable, technologically advanced, and environmentally-sound. Energy must be reliable – provided when and where needed and with minimal environmental risks and impacts. Energy must be affordable to households, businesses and industry, and motorists – and in particular to disadvantaged customers who rely on California government to ensure that they can afford this fundamental commodity. EAP actions must be taken with clear recognition of cost considerations and trade-offs to ensure reasonably priced energy for all Californians.

The EAP accomplishes these goals in the electricity sector by calling for a “loading order” specifying the priority order for how to balance electricity supply and demand. The loading order identifies energy efficiency and demand response as the State’s preferred means of meeting growing electrical energy needs. After cost-effective efficiency and demand response, it relies on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, the loading order supports clean and efficient fossil-fired generation.

The Role of the HHSEGS in Energy Displacement

The Renewables Portfolio Standard (RPS) was established by Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002), effective January 1, 2003, with revisions to the law following as a result of Senate Bill 1250 (Perata, Chapter 512, Statutes of 2006), Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006), and Senate Bill X1 2 (Simitian, Chapter 1, Statutes of 2011, First Extraordinary Session). The RPS originally required California’s electric utilities to obtain at least 20 percent of its power supplies from renewable sources by 2010. It now has been expanded to require retail sellers of electricity and local publicly owned electric utilities (POUs) to increase the amount of renewable energy they procure until 33 percent of their retail sales are served with renewable energy by December 31, 2020. Under the law, the Energy Commission is required to certify eligible renewable energy resources that may be used by retail sellers of electricity and POUs to satisfy their RPS procurement requirements, develop an accounting system to verify retail sellers’ and POUs’ compliance with the RPS, and adopt regulations specifying procedures for enforcement of the RPS for the POUs.

As California moves towards an increased reliance on renewable electrical energy by implementing the RPS, non-renewable electric energy resources will be displaced. A 33 percent RPS is forecasted to require California load-serving entities to procure more than 95,600 GWh of renewable electrical energy, an increase of roughly 55,000 GWh over 2010 levels.[18]

Given an RPS, renewable electrical energy displaces electricity that would otherwise be produced from coal- and natural gas-fired generation. The construction and operation of the HHSEGS would not displace other renewable resources as load-serving entities must meet the renewable energy purchase requirements embodied in the RPS. Even in the absence of an RPS, HHSEGS would not replace other renewables. The fuel and other variable costs associated with most forms of renewable generation are much lower than for other resources and, (b) even where this may not be the case (e.g., selected biofuels) the renewable resource will frequently have a “must-take” contract with a load-serving entity requiring that all of electrical energy produced by the project be purchased by the buyer. Hydroelectric generation is not displaced as it has very low variable costs of production; the variable cost of nuclear generation is much lower than for fossil resources as well.

[18] Retail sales requiring renewable procurement are forecasted to be almost 287,000 GWh in 2022 (CEC 2012); purchases of renewable energy are estimated to have been 41,000 GWh (CEC 2011a)

While the HHSEGS would combust some natural gas and thus emit GHGs as part of its operations, it would produce far less GHG emissions (emitting approximately 95 lbs CO_2/MWh) than the coal- and natural gas-fired resources it would displace. Coal-fired generation requires the combustion of 9,000 – 10,000 Btu/MWh, resulting in more than 1,800 lbs CO_2/MWh. Natural gas-fired generation in California requires an average of 8,566 Btu/MWh, yielding approximately 1,000 lbs CO_2/MWh (CEC 2011b).[19]

The Role of the HHSEGS in Capacity Displacement

The HHSEGS would provide up to 500 MW of electrical capacity and associated electrical energy to the grid during early afternoon hours in the summer. Electricity demand in California reaches its peak during mid- to late-afternoon on the hottest weekdays of the summer. Dependable capacity – the amount of capacity that can be counted upon to be available during the peak - is needed to reliably serve loads; the generation fleet, in conjunction with demand response programs, must provide a sufficient amount of dependable capacity to meet demand on the highest load day of the year.[20] Load-serving entities in the California ISO control area, for example, are required by the California ISO to procure dependable capacity in amounts determined by their peak load forecast.

While the HHSEGS's dependable capacity value would depend upon its exact performance, its ability to sustain output even when solar irradiance is reduced due to cloud cover, and thus provide energy during extreme peak hours would mean a higher value than would otherwise be the case.

The dependable capacity provided by the HHSEGS would assist in replacing that lost due to the Emissions Performance Standard (EPS) and the State Water Resources Control Board's (SWRCB) once-through cooling (OTC) policy, both discussed more fully below.

Replacement of High GHG-Emitting Generation

High GHG-emitting resources, such as coal, are effectively prohibited from entering into new long-term contracts for California electricity deliveries as a result of the Emissions Performance Standard adopted in 2007 pursuant to SB 1368. Between now and 2020, 1,549 MW of coal-fired generation capacity will have to reduce GHG emissions or be replaced; these contracts are presented in **Greenhouse Gas Table 5**.

Retirement of Generation Using Once-Through Cooling

The State Water Resource Control Board's (SWRCB) policy on cooling water intake at coastal power plants has led to the retirement and replacement of several plants that use once-through cooling (OTC), numerous others are likely to retire on or prior to

[19] The HHSEGS would displace resources with a higher than average heat rate during most hours, as the most expensive (least efficient) resources would be displaced.

[20] This is usually the hottest weekday in the summer, when residential and commercial cooling loads are at their highest.

assigned compliance dates,[21] some of which will require replacement.[22] The units with compliance dates on or before the end of 2020 are presented in **Greenhouse Gas Table 6**

Greenhouse Gas Table 5
Expiring Long-term Contracts with Coal-fired Generation 2009 – 2020

Utility	Facility	Contract Expiration	MW
Department of Water Resources	Reid Gardner	2013 [1]	213
SDG&E	Boardman	2013	84
SCE [2]	Four Corners	2016	720
Turlock Irrigation District	Boardman	2018	55
LADWP	Navajo	2019	477
		TOTAL	**1,549**

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.
Notes:
1. Contract not subject to Emission Performance Standard, but the Department of Water Resources has stated its intention not to renew or extend.
2. The sale of SCE's share of Four Corners to Arizona Public Service has been approved by the CPUC and is awaiting FERC approval.

[21] Most of the OTC units are aging facilities, for which extensive retrofits will be uneconomical. While compliance using operational and structural controls is allowed, the ability of units to comply in this manner and still operate in a fashion that yields a sufficient revenue stream is questionable.

[22] The California ISO, CPUC and the Energy Commission are studying amount of OTC capacity that will require replacement.

Greenhouse Gas Table 6
OTC Units with SWRCB Compliance Dates on or before December 31, 2020[23]

Plant, Unit Name	Local Reliability Area	Capacity (MW)
Alamitos 1-6	L.A. Basin	1,970
Contra Costa 6, 7	S.F. Bay	680
El Segundo 3, 4	L.A. Basin	670
Encina 1-5	San Diego	951
Huntington Beach 1, 2	L.A. Basin	430
Huntington Beach 3, 4	L.A. Basin	450
Mandalay 1, 2	Ventura	436
Morro Bay 3, 4	None	600
Moss Landing 6, 7	None	1,404
Moss Landing 1, 2	None	1,080
Ormond Beach 1, 2	Ventura	1,612
Pittsburg 5-7	S.F. Bay	1,332
Redondo Beach 5-8	L.A. Basin	1,343
Total		12,958

Note: Pittsburg Unit 7 (682 MW) does not use once-through cooling but would be required to shut down if Units 5 and 6 retire.

GHG Emissions During Plant Operation

The HHSEGS would produce GHG emissions during operations, combusting natural gas in order to provide assistance in starting the solar boiler and increase or sustain energy output during periods of reduced solar irradiance (early morning and late afternoon hours, periods of high cloud cover)

The ability to produce energy for both station service and transmission to end-users slightly earlier and slightly later than would otherwise be the case without limited supplemental firing, as well as to smooth out fluctuations in output during periods when solar irradiance is interrupted has not only economic value to the owner, but provides reliability to the electricity system. The substantial amounts of solar capacity anticipated for development during the coming decade and beyond, combined with the retirement of perhaps as much as 13,000 MW of gas-fired generation using once-through cooling, is very likely to shift the system peak to late afternoon/early evening when solar resources would produce little if any energy and gas-fired resources would have to be dispatched to provide reserves. Similarly, gas-fired generation would be needed in the early morning when solar resources have yet to ramp up and wind generation is failing. The ability of the HHSEGS to provide energy during early morning and late afternoon/early

[23] Greenhouse Gas Table 6 does not include OTC units that retired prior to January 1, 2012, resources with compliance dates through 2020 that have already been slated for replacement (e.g., LADWP units at Haynes and Scattergood), or units with post-2020 compliance dates (the remaining units at Haynes and Scattergood, LADWP's Harbor combined cycle, and the nuclear facilities at San Onofre and Diablo Canyon)

evening hours using natural gas fueled equipment, as well as to sustain output under less-than-ideal conditions on extreme load days not only reduces the need to dispatch natural gas-fired generation but may, in some cases, obviate the need to build it.

The ability to sustain output levels during periods of extreme loads also reduces the need for regulation services. As the HHSEGS would be able to “ride through” brief periods of reduced irradiance, it would reduce the need for resources to be dispatched solely to adjust output in response to short-term changes in intermittent generation levels. This benefit is in addition to increasing the dependable capacity of the project and thus reducing the need for gas-fired capacity to meet dependable capacity requirements.

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification related to greenhouse gas emissions are proposed. The project owner would comply with mandatory ARB GHG emissions reporting regulations (California Code of Regulations, tit. 17, Subchapter 10, Article 2, Sections 95100 et. seq.) and/or future GHG regulations formulated by the U. S. EPA or the ARB, such as GHG emissions cap-and-trade requirements.

CONCLUSIONS

The HHSEGS would emit considerably less greenhouse gases (GHG) than existing power plants and most other generation technologies, and thus would contribute to continued improvement of the overall western United States, and specifically California, electricity system GHG emission rate average. The proposed project would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California. Thus, staff concludes that the proposed project’s operation would result in a cumulative overall reduction in GHG emissions from the state’s power plants and that any short-term impacts would be less than significant.

Staff concludes that the GHG emission increases typical from construction and decommissioning activities would not create significant impacts under CEQA for several reasons. First, the periods of construction and decommissioning would be short-term and not ongoing during the life of the proposed project. Second, the best practices control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize greenhouse gas emissions since the use of newer equipment would increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. Finally, the construction and decommissioning emissions are miniscule when compared to the reduction in fossil-fuel power plant greenhouse gas emissions during project operation. For all these reasons, staff would conclude that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would be offset during proposed project operations and would, therefore, not create a significant impact under CEQA.

The HHSEGS, as a renewable energy generation facility, is determined by rule to comply with the Greenhouse Gas Emission Performance Standard requirements of SB 1368 (Title 20, Greenhouse Gases Emission Performance Standard, Section 2900 et. seq.). The project is not subject to the requirements of SB 1368 (Greenhouse Gasses Emission Performance Standard; Cal. Code Reg., tit. 20, § 2900 et. Seq.) and the Emission Performance Standard; however, it would nevertheless meet the Emission Performance Standard.

STAFF PROPOSED FINDINGS OF FACT

1. GHG emissions from the HHSEGS project construction are estimated to be 10,089 MTCO2E during the 29-month construction period, which is the annual equivalent of 4,175 MTCO2E per year.
2. Construction GHG emissions would be minimal in comparison to the GHG emission reductions that the project would create in its lifetime, with annual GHGs estimated at up to 61,628 MTCO2E per year as shown in **Greenhouse Gas Table 3**.
3. HHSEGS would use best practices to control its construction-related GHG emissions.
4. Construction-related GHG emissions are less than significant if they are controlled with best practices.
5. State government has a responsibility to ensure a reliable electricity supply, consistent with environmental, economic, and health and safety goals.
6. California utilities are obligated to meet whatever electricity demand exists from any and all customers.
7. Under SB 1368 and implementing regulations, California's electric utilities may not enter into long-term commitments with base load power plants with CO_2 emissions that exceed the Emissions Performance Standard ("EPS") of 0.5 MTCO2 / MWh.
8. The maximum annual CO_2 emissions from HHSEGS operation would be 61,628 [24] MTCO2, which constitutes an emissions performance factor of 0.043 [25] MTCO2 / MWh.
9. The HHSEGS is a solar project that would operate at less than a 60 percent capacity factor, and therefore is not subject to the requirements of the SB 1368 Emissions Performance Standard. Nonetheless, the HHSEGS would easily meet the Greenhouse Gas Emission Performance Standard required by SB 1368.
10. AB 32 requires ARB to adopt regulations that will reduce statewide GHG emissions, by the year 2020, to the 1990 level. Executive Order S-3-05 requires a further reduction, by the year 2050, to 80 percent below the 1990 level.
11. The California Renewable Portfolio Standard (RPS) requires the state's electric utilities obtain at least 20 percent of the power supplies from renewable sources, by the year 2010.

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[24] Includes mirror washing – otherwise the maximum emission is 40,481 MTCO2E

[25] Includes mirror washing – otherwise around 0.028 MTCO2.MWh without including mirror washing emission estimates

12. Senate Bill X1-2 increases the RPS target requirement to 33 percent by 2020.
13. California's power supply loading order requires California utilities to obtain their power first from the implementation of all feasible and cost-effective energy efficiency and demand response, then from renewable energy and distributed generation, and finally from the most efficient available fossil-fired generation and infrastructure improvement.
14. Operation of HHSEGS would be consistent with the loading order.
15. HHSEGS would displace generation from higher-GHG-emitting power plants.
16. HHSEGS would replace power from coal-fired power plants that would be unable to enter into new contracts or renew contracts with California utilities under the SB 1368 EPS, and from once-through cooling power plants that must reduce their use of coastal or estuarine water.
17. HHSEGS operation would reduce overall GHG emissions from the electricity system.

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Air Quality / GHG

List of Comment Letters

1	Applicant, BrightSource Energy, Inc.
2	Intervenor Cindy MacDonald
3	Intervenor Center for Biological Diversity
4	Intervenor, Old Spanish Trail Association
5	Inyo County
6	Bureau of Land Management
7	National Park Service
8	The Nature Conservancy
9	Amargosa Conservancy
10	Pahrump Paiute Tribe
11	Richard Arnold, Pahrump Piahute Tribe
12	Big Pine Tribe of Owens Valley
13	Basin & Range Watch

[1] Note - not all comments from the applicants are show in this comments matrix. Only those comments that were have a comment associated explanation rather than a text change within the document of the Final Staff Assessment are listed in this matrix. If there was a text change and CEC staff agrees with the change requested by the applicants the change has been made in the staff analysis.

[2] Note: the GBUAPCD has responses to some of the questions that are an attachment to the Final Determination of Compliance for HHSEGS and will be noted as "GBUAPCD response", CEC staff concur with the responses and have included the responses below for convenience of having all responses in the same location.

Comment	DATE	COMMENT TOPIC	RESPONSE
1	**July 23, 2012**	**[1]APPLICANT -- BrightSource Energy, Inc.**	
1.1		Project Description -- transmission interconnection description modification	Staff agrees. See page 4.1-13 of the FSA.
1.2		Project Description -- Kern River Gas Transmission Company (KRGT) gas line	Staff agrees. See page 4.1-13 of the FSA.
1.3		Project Description -- acreage / footprint	Correct acreage of 3,277 is now reflected throughout FSA
1.4		Project Description -- distance to Pahrump, NV	The distance to site from Pahrump, NV has been corrected throughout the document to reflect the correct distance.
1.5		Conditions requiring a third party review need to incorporate a 2 week limit for review and comment on the required documents.	Staff agrees. See General Conditions.
1.28	Comment 28	Page 4.1 23, Construction Impacts Mitigation, Items L and N: Applicant did not propose these items. Also, “top service shape” (in Item N) is ambiguous, and unenforceable as a practical matter; thus, delete Item N. Revise	Staff has decided to re-word instead of delete as applicant suggests. Text has been changed to say: "N. Construction equipment will be maintained as specified by OEM (original equipment manufacturers)".
1.45	Comment 45. The Applicant requests that changes be made to the following conditions of certification:	AQ-SC2: Applicants have suggested to change 30 days to 15 days.	Staff has changed to: "15 business days from the date of receipt."
	Comment regarding AQ-SC3	Various condition edits to the condition.	Staff does not agree to the proposed changes to staff condition **AQ-SC3**. The wording in **AQ-SC3** is appropriate for the proposed project and is consistent with what has been used on other Energy Commission projects.
Comment	**DATE**	**COMMENT TOPIC AIR QUALITY SECTION 3**	**RESPONSE**
2	**July 21, 2012**	**[2]INTERVENOR -- Cindy MacDonald**	

1. TEMPORARY CONSTRUCTION/COMMON AREA EMISSIONS	Question 1.1	Under which “heading” in Appendix 5.1F, has the applicant included the emissions impacts from construction and development of the temporary construction site and common area?	Construction of the temporary construction site and common area has been included in the emissions estimates of Appendix 5.1F in the Boiler Optimization document. Please find those estimates in the table heading titled "Solar Field Assembly and Installation, Concrete Batch Plant, and Miscellaneous".
2. CONSTRUCTION EQUIPMENT EMISSIONS FACTORS: DEFINING MILES PER HOUR	Question 2.1	In the Construction Equipment Emission Factors, what is the column title, “Tier (Nonroad), Avg. mph (Onroad)”, referring too – average miles per hour the vehicle is estimated to travel or average speed of the vehicle?	GBUAPCD Response: The column shows the US EPA/California ARB engine certification tier (mainly Tier 3) for nonroad vehicles, and the average miles traveled per hour of travel for onroad vehicles. The differing units are needed because the conventions for calculating emissions from nonroad and offroad equipment differ. Exhaust emissions from nonroad equipment are typically calculated per unit of operating time (i.e., grams per horsepower per hour); whereas, exhaust emissions from onroad vehicles are calculated per distance the vehicle travels (i.e., grams per mile).
	Question 2.2	If the Construction Equipment Emission Factors in the column titled, “Tier (Nonroad), Avg. mph (Onroad)”, is referring to emissions resulting from the speed of the vehicle, how accurate are these emissions when the conditions of the permit authorize speeds up to 10-25 mph, depending on surface type?	GBUAPCD Response: For on-road vehicles, the average miles traveled during an hour of travel (10) is an activity level, not a speed. The distance (in vehicle miles traveled per hour) is multiplied by the emission factors (in grams per vehicle mile traveled) to calculate pounds per hour of emissions from on-road-type vehicles. The speed limit of 25 mph applies to instantaneous speed, while the average miles the vehicle is estimated to travel during an hour reflects the average distance traveled over an entire hour, including stops.
	Question 2.3	If the emissions were calculated for non-road vehicles using a 10 mph vehicle speed, what is the difference (if any) in emissions impacts?	GBUAPCD Response: Emissions from non-road vehicles were not calculated using a 10 mph vehicle speed—they were calculated using Tier-specific emission factors that are not speed-based.
3. SF6 MAINTENANCE, REPLACEMENT AND WITHDRAWAL REQUIREMENTS	Question 3.1	What are the annual anticipated maintenance, replacement and withdrawal requirements of SF6 at the proposed project site as well as over the life of the project?	SF6 recharge (maintenance or replacement) may be required periodically to replace the SF6 lost due to leakage or contamination of the system and this rate of loss has been included in the GHG section of the FSA. Please see GHG Table 3 "HHSEGS Estimated Potential Greenhouse Gas (GHG) Emissions" under column SF6.
	Question 3.2	Where has the applicant disclosed this information in the AFC files or subsequent documents and where has CEC Staff accounted for them in the PSA?	The applicants have estimated an SF6 loss in the revised April 2012 "Boiler Optimization" document found in the Appendix 5.1B, Table 5.1B-13R. California Energy Commission staff has included an estimate in GHG table 3 - "Equipment leakage (SF6)".
4. SWITCHYARD CONTRADICTIONS/CHANGES IN SF6 STORAGE QUANITIES	Question 4.1	Is the new location of the switchyard on public or private land?	The proposed switchyard would be located on private land.
	Question 4.2	If the switchyard is moved outside of the CEC’s jurisdiction, does this effectively eliminate the CEC’s ability to evaluate and incorporate this portion of the proposed project in their direct, indirect and cumulative emissions and impact analysis?	If the switchyard is moved outside California, it would be outside the jurisdiction of the California Energy Commission. The California Energy Commission only has permitting authority within the state.
	Question 4.3	If the switchyard is moved out of state, will the CPM or any other California based entity or agency have any jurisdiction over its compliance to LORS over the life of the project?	If the switchyard is moved outside of California, it would be outside the jurisdiction of the California Energy Commission. The California Energy Commission only has permitting authority within the state.
	Question 4.4	Given the amount of contradictory information presented, can anyone explain what proposal we are suppose to be analyzing and commenting on?	The current project analyzed in the FSA and PSA is the "Boiler Optimization" configuration submitted April 2012.

	Question 4.5	Why has the amount of onsite SF6 increased if no changes in circuit breaker requirements have been introduced?	Please see the corrected value of SF6 in GHG Table 6.
	Question 4.6	What is the reason(s) for this increase in onsite storage of SF6, especially in light of the fact that the switchyard is supposedly no longer included in the California portion of the proposed project's design?	Staff believes the original value of SF6 was an error; the correct value is seen in GHG Table 3. The switchyard would be located in the California portion of the proposed project.
	Question 4.7	What is the specific emissions factor increase relative to this 400 lb increase in SF6 onsite storage quantities, including annual GHG impacts in terms of pounds/tons?	The SF6 quantity is not expected to change. Please see GHG Table 3 for the emission leakage rate of SF6.
5. CONCRETE BATCH, EMISSIONS CALCULATIONS AND HOURS OF OPERATION	Question 5.1	If the Concrete Batch Plant is estimated to operate for 21 hours per day, why is its associated equipment only projected to operate for 8 and 5 hours a day? Please explain timetables and operating procedures and explain why the California Energy Commission Staff found them acceptable for emissions calculations.	California Energy Commission staff believes the emissions estimate of 21 hours per day is conservative. The analysis assumes that up to two loaders and 20 transmix trucks will each operate up to 8 and 5 hours per day, respectively. This results in a total of 16 loader-hours per day and 100 transmix vehicle-hours per day of operation when the concrete batch plant is in operation. Because the plant operates in batch and not continuous mode, the loaders would not be expected to operate continuously for 21 hours. The five operating hours per day (when loading is not occurring) represents periods of time throughout the day when the plant has an adequate quantity of aggregate stored in its hopper for the current (or next) batch.
	Question 5.2	What are the actual "peak" months the Concrete Batch is projected to operate; September/October of 2013, March, April and May of 2014 or September 2013 through May 2014?	According to Table 5.1F-1 of the Boiler Optimization, the peak construction Max daily emissions would be around Month 8 and 9 due to fugitive dust from the concrete Batch Plant. Depending on the start of construction, month 8 and 9 could be in 2013 or in 2014.
	Question 5.3	Based on the answer to question 2, what are the true cumulative emissions totals that will occur during those months of "peak" Concrete Batch operations?	Please see Table 5.1-F of the Boiler Optimization.
	Question 5.4	How does Staff justify the use of 16 days emissions impacts during Concrete Batch Operations under the "hourly" emissions calculations when they know the Plant is already projected to operate for 21 hours per day and will operate "around the clock" for at least three months?	GBUAPCD Response: The hourly and daily construction equipment activity schedules were developed from the initial annual estimates based on a 16-day-per-month (4 days per week, 10 hours per day) operating schedule in order to conservatively overestimate worst case hourly and daily emissions. If a 5-day-per-week schedule had been assumed, the number of concurrently operating vehicles and/or the number of vehicle operating hours per day (or some combination of the two), would be reduced by 20 percent to accomplish the scheduled weekly construction tasks. For example, with a 5-day work week, daily working hours would be reduced from 10 to 8 (to maintain a 40 hour work week) and peak daily emissions would be 20 percent lower than the emissions analyzed.
6. MAXIMUM BOILER EMISSIONS: CONFLICTING DATA	Question 6.1	1. What are the reasons for these annual operating hour discrepancies?	Rather than limit the operating hours of the individual boilers on a daily, monthly or annual basis, the District also accepted the applicant's estimated

	Question 6.2	What differences do these variations in annual operating hours for boilers make to operating emissions impacts and emission limits in the Permit To Operate?	hours of operation. From the estimates, daily and annual natural gas fuel limits were derived in Table 5.1B-9R of the revised Boiler Optimization tables that will act as emission control limits for ensuring the 24-hour and annual impacts would be below the state and/or federal ambient air quality standards. The total natural gas fuel consumption, expressed as heat input rates, shall not exceed 3,440 MMBtu/day or 746,400 MMBtu/year for combustion in the burners of all auxiliary and nighttime preservation boilers in the Solar 1 facility or the adjacent Solar 2 facility.
7. ANNUAL POWER PRODUCTION	Question 7.1	Does the applicant's annualized capacity factor of approximately 3,000 full-load hours per year indicate this is the projected annual average of hours the plant will produce power over the course of that year?	Refer to the Response to Comments table in the **Efficiency and Facility Design** section of this FSA.
	Question 7.2	What is the daily power production potential in terms of hours during the peak summer months of June, July and August, when solarity is the highest due to long summer days?	
	Question 7.3	Due to potential increased production levels during summer months by possibly a large margin, can the proposed project's emissions qualify as a "seasonal" production facility subject to air pollution reporting requirements for seasonal generation? If not, why not?	The applicant is not requesting to be licensed as a "seasonal" source. Further, the local air district does not have any regulations for seasonal air pollution sources. Staff did not evaluate the project as a seasonal source.
8. HELIOSTAT COMMUNICATIONS SYSTEM: TRENCHING/IMPACTS TO AIR QUALITY & EMISSIONS	Question 8.1	If the applicant chooses to directly wire the heliostats, how many feet/yards/miles of trenching will be required and what does this translate to in terms of acreage disturbance at the project site?	Refer to the Response to Comments table in the **Soils and Surface Water** section of this FSA.

	Question 8.2	If the applicant chooses to directly wire the heliostats, what is the projected increase in heavy equipment required to install it, the projected cumulative increase in construction emissions from equipment and potential traffic impacts and was this accounted for in the AFC files or the PSA? If so, where?	If the applicants choose to directly wire the heliostats, installation would be using vehicles such as the tractors and pickup trucks that are already included in the construction equipment schedule. The construction emissions will be approximately the same as those for a wireless system and no increase in emissions would be expected. In the FSA this is included in Air Quality Table 7 "HHSEGS Construction Emissions" under Maximum Daily onsite and Offsite Emissions.
	Question 8.3	What are the estimated number of additional workers trenching would require during the construction phase, what hours of the day would they trench, what months would this affect during the construction portion of the project, how many feet/yards/miles is projected to be completed each day and was this accounted for in the AFC files or PSA? If so, where?	
9. CONFLICTING DATA ON MAINTENANCE ROAD DESIGNS: IMPACTS TO AIR QUALITY/EMISSIONS	Question 9.1	How many roads circle the power towers for each plant under each design element (20-ft versus 10 ft)?	Refer to the Response to Comments table in the **Soils and Surface Water** section of this FSA.
	Question 9.2	What is the projected total surface in acreage values for each of these maintenance road design elements and what is the difference in values between them? Example, 20-ft roads result in 500 acres of disturbance, 10-ft roads result in 1,000 acres of disturbance.	Refer to the Response to Comments table in the **Soils and Surface Water** section of this FSA.
	Question 9.3	How many miles of roads for each kind of road (paved, fully graded, partially graded) is the completed proposed project projected to have?	When assessing the amount of soil disturbance, staff is concerned with the area of roadway rather than the number of miles. The analysis is calculated by using the acreage of disturbed land.
	Question 9.4	What is the total number of square feet for each kind of road (paved, fully graded, partially graded) that will be incorporated into the proposed project sites operational design?	Refer to the Response to Comments table in the **Soils and Surface Water** section of this FSA.
	Question 9.5	What are the differences (if any) in emissions impacts via fugitive and windblown dust (PM10/PM2.5 particles) between these two variations of designs for the drive zones/maintenance paths surrounding the power towers? If so, were they accounted for in the AFC operational emissions data? If so, where?	All PM10 and PM2.5 emissions were estimated including those from windblown dust and fugitive dust caused by vehicles.
	Question 9.6	What is the projected PM10/PM2/5 fugitive and windblown dust for hourly, daily and annual emissions during the operational portion of the proposed project as a result of the drive zones/maintenance paths without mitigation measures and with mitigation measures?	Please see **AQ Table 7**, in the operational data table, emissions include mitigation measures.
	Question 9.7	What are the maximum hourly, daily and annual emissions limits for fugitive and windblown dust during the operational portion of the proposed project?	
10. MIRROR WASHING MACHINES AND MAINTENANCE SCHEDULE: NOT FEASIBLE	Question 10.1	Approximately, how many mirrors are projected to be included in each zone - Near Tower Zones and the Far From Tower Zones?	The project as a whole would have 170,000 heliostats, or 340,0000 mirrors. This is found in the Project Description section. Information about the number of heliostats and mirrors in each zone was not needed for staff's analysis.

	Question 10.2	How long will is take to clean each mirror per zone?	The applicant proposed washing the mirrors in the near-tower (NT) zone on a 2-week rotating cycle. The water washing would be supplemented with brushing, which would be done on an 8-week cycle. Emissions for the NT Zone were based on 4,000 vehicle miles traveled per power plant per year. Staff feels this is a reasonable estimate for evaluating emissions for NT mirror washing, especially fugitive dust emissions. The result is most likely conservative because staff has estimated VMT as much less than this value, which was submitted by the applicant. See answer to Question 10.4 for the FFT Zone.
	Question 10.3	Based on only employing 1 MWM in the NT Zone, what is the projected length of time it would take to complete one rotating cycle of general maintenance (cleaning, not scrubbing) per solar plant?	
	Question 10.4	Based on only employing 7 MWM's in the FFT Zone, what is the projected length of time it would take to complete one rotating cycle of general maintenance (cleaning, not scrubbing) per solar plant?	The applicant proposed washing the mirrors in the far-from-tower (FFT) Zone on a 2-week rotating cycle. The water washing would be supplemented with brushing, which will be done on an 8-week cycle. Emissions for the FFT Zone were based on 18,900 Vehicle miles traveled per HHSEGS power plant per year. Staff feels this is a reasonable estimate for emissions from mirror washing in the FFT Zone, especially fugitive dust emissions. The result is most likely very conservative because staff has estimated VMT as much less than this value submitted by the applicant.

	Question 10.5	How many additional MWM's would be necessary to keep the applicant's stated 2-week rotating cycle cleaning schedule for each zone and what would be the hourly, daily and annual emissions increases to accommodate these additional MWM's per zone?	Mirror washing emissions are calculated on a hourly, daily, and annual basis. Please see Air Quality Table 8 for all criteria pollutants and GHG Table 3 for Green House Gas emissions estimates for mirror washing activities, which include the Near Tower Zone and the Far From Tower Zone. Emissions were based on vehicle miles traveled (VMT) not on the number of mirror washing machines (MWMs).
	Question 10.6	Will additional MWM's or vehicles be required to complete the projected additional maintenance of mirror "scrubbing"? If not, what changes will be made to the time it takes to complete the regularly rotating schedule per zone? If so, how many additional MWMs or vehicles will be required per zone and what are their additional operational emissions impacts?	California Energy Commission staff believes there may not be a need for additional MWM vehicles necessary for scrubbing. Emissions were based on vehicle miles traveled (VMT), not the number of mirror washing machines (MWMs).
11. OPERATIONAL DUST CONTROL PLAN: INADEQUATE IMPACT ANALYSIS	Scenario 1: Question 11.1	How much medium sized gravel would be required for complete coverage of all fully and partially graded dirt roads required for project operations at a depth of 3" thick?	Alternatives analysis for 3" thick gravel was not included in the staff analysis, and staff does not need to know that in order to recommend issuance of the license. The applicant may be able to provide this information for the commenter. Currently staff has only assumed 1 inch gravel thickness. Please see **Soils and Surface Waters** section for more detailed information.
	Scenario 1: Question 11.2	How many delivery trucks would be required to deliver the proposed gravel in Question 1?	
	Scenario 1: Question 11.3	What would be the additional construction emissions factors for delivery trucks that hauled the proposed gravel in Question 1 to the site?	
	Scenario 1: Question 11.4	If medium sized gravel was applied to all fully and partially graded roads required for the proposed projects operations at a depth of 3" thick, would chemical dust suppressants/soil binders also be required to reduce fugitive and windblown dust?	
	Scenario 1: Question 11.5	If medium sized gravel at a 3" depth was applied to all fully and partially graded roads required for the proposed projects operations at a depth of 3" thick, to what degree would this offset vehicular emissions resulting from chemical dust suppressants/soil binders applications over the life of the project?	
	Scenario 2: Question 11.1	What product will be used?	At this point the soil binder product that would be used is not known. However BrightSource has submitted information for a product called Soil Sement which they have suggested for use on the current Ivanpah project. This product is pre-certified by the ARB and is approved by the California Regional Water Board (Fitz, 1996).
	Scenario 2: Question 11.2	How often must it be reapplied: once a month, once a year?	The rate of reapplication would be as-needed and would be determined by the project owner, during construction and operation of the facilities. The facility owner will be required to use approved suppressants and methods of application.
	Scenario 2: Question 11.3	What methods will the applicant apply these chemicals with: by hand or by vehicle?	The applicants would need to submit this information in the Air Quality Construction Mitigation Plan (AQCMP) at least 60 days prior to the start of any ground disturbance. The applicant would need to include the VMT and emissions as part of this plan.
	Scenario 2: Question 11.4	If vehicles are used, (which given the amount of coverage it appears will be needed, this is the most reasonably foreseeable choice), what kind of vehicles will they be?	

	Scenario 2: Question 11.5	What are their daily, monthly and annual emissions during the operational portion of the project?	Please see Air Quality Table 10.
	Scenario 2: Question 11.6	What limitations will apply and/or mitigation measures will reduce the introduction of these additional vehicle emissions impacts over the life of the project?	**AQ-SC6** requires the facility owner to submit to the CPM a plan that identifies the size and types of the on-site vehicles and equipment fleet, and the vehicle and equipment purchase orders and contracts and/or purchase schedules. The plan must be updated every other year and submitted in the Annual Compliance Report (**COMPLIANCE-7**). In addition, **AQ-SC7** requires the facility owner to submit to the CPM for review and approval a plan that identifies dust and erosion control procedures that will be used during operation of the project. The required information includes effectiveness and environmental data for the proposed soil stabilizer all locations of speed limit signs.
	Scenario 2: Question 11.7	Will the application and dispersal of these chemical dust suppressants/soil binders be prohibited during days where there is wind to prevent accidental application on native vegetation and inappropriate air dispersal? If not, what will be the wind speed limitation: 5 mph, 10 mph, etc.?	Staff is not proposing a condition of certification on the application and dispersal of the chemical dust suppressants. However, the facility owner would be required to use ARB and District approved dust suppressants and methods of application.
	Scenario 2: Question 11.8	How long will it take the applicant to reapply these substances (daily, weekly, monthly, annually?)	This would depend on the scheduling by the project owners and would be part of the air quality mitigation plan requiring approval by California Energy Commission staff.
	Scenario 2-A: Question 11.1	Based on the application requirements, precautions and effectiveness for two CARB precertified chemicals listed above, what are the site-specific limitations, requirements, direct, indirect and cumulative impacts to the proposed project site and surrounding environment for each of these products individually during both the construction and operational phase as well as over the life of the project?	This would depend on the scheduling by the project owners, and would be part of the air quality mitigation plan requiring approval by California Energy Commission staff. The facility owner will be required to use approved suppressants and methods of application.
	Scenario 2-A: Question 11.2	How does the grading and surface requirements for effective application of these two CARB precertified products affect the applicant’s intent to implement a Low Impact Design to preserve natural washes and drainages throughout the proposed project site?	
	Scenario 2-A: Question 11.3	What is the estimated number of acres any of these products will be applied to during the construction and operational phase of the proposed project?	The applicants estimates during construction are: (1) fully graded dirt roads (12' & 20' width) at 18.2 acres and (2) partially graded dirt roads (10' width) at 171 acres.
	Scenario 2-A: Question 11.4	What are the estimated daily, monthly and annual vehicle passes per kind of road (fully graded and partially graded) that will be required for both the construction and operational phase of the proposed project?	Please see Air Quality Table 8 under "Maintenance Vehicles" and "Employee and Delivery Vehicles" for estimates of daily, monthly, and annual emissions.

	Scenario 2-A: Question 11.5	How much in terms of acres (if any) of the proposed project site could be classified as “not suitable” for application of either of the two CARB precertified dust suppressants/soil binders?	Soil stabilizers would be used for "unpaved, and minimally used roads". These are to be used only for dust suppressant, and are not meant to be in place of gravel or paving. The facility owner would be required to use approved suppressants and methods of application.
	Scenario 2-A: Question 11.6	What are the public health implications (if any) if any of these considerations increase fugitive and windblown dust (PM10/PM2.5 particles) due to lack of site suitability (soils, road surface, aggregate, natural drainage) in terms of applying either of these two CARB precertified products?	Refer to the Response to Comments table in the **Public Health** section of this FSA.
	Scenario 2-A: Question 11.7	What evidence is available that supports the effectiveness and dust control rates of these two CARB precertified dust suppressants/soil binders with respect to heavy-duty equipment such as will be used during both the construction and operational phase at the proposed project site?	Information on available soil stabilizers is at: http://www.avaqmd.ca.gov/Modules/ShowDocument.aspx?documentid=2705
	Scenario 2-A: Question 11.8	Do any of these considerations trigger significant impact thresholds to air quality? If so, what is the level (in terms of percentage) of the significance and by what degree do the proposed mitigation measures individually (by percentage) reduce those impacts?	No, they do not trigger significant impact thresholds to air quality. Soil stabilizers could potentially reduce fugitive dust emissions by up to 80%.
	Scenario 2-A: Question 11.9	Since PennzSuppress® D is not recommended for multiple areas related to water and water drainage, what are the projected direct, indirect and cumulative impacts to water, ground water, waters of the state and biological resources at and around the project site? if this product is approved of in the dust control plans currently scheduled to be formulated after the CEQA equivalency process is closed?	This product has not been submitted in a dust plan and has not been reviewed nor evaluated by California Energy Commission staff. Before any dust suppressant is approved for use, it will be evaluated and only approved materials would be allowed.
	Scenario 3: Question 11.1	If the applicant uses water trucks to control fugitive and windblown dust over the life of the project, what are the additional water annual water requirements and can they be met with the currently proposed water limitations?	Refer to the Response to Comments table in the **Water Supply** section of this FSA.
	Scenario 3: Question 11.2	If the applicant uses water trucks to control fugitive and windblown dust over the life of the project, what are the additional emissions impacts the water trucks will add to operations on a daily, monthly and annual basis?	This has been taken into consideration in emission estimates in Air Quality Table 8 - row "Maintenance Vehicles (mirror washing)".
	Scenario 3: Question 11.3	Given the significant difference in emissions resulting from the applicant’s change of use to on-road heavy duty engines for the Mirror Washing Machines versus the original AFC plans of using tractor trailers, will California Energy Commission Staff propose as a Condition of Certification that if water trucks are used over the life of the project as part of the dust control plant that they also be equipped with on-road heavy duty engines to reduce emissions impacts?	For all dedicated vehicles, including those for mirror washing, **AQ-SC6** requires the facility owner to obtain new model year vehicles that meet California on-road vehicle emission standards for the model year when obtained.
	Scenario 3: Question 11.4	How can the 200,000 to 400,000 gallons of recycled water be counted on for dust control if its discharge depends on the fluid sample levels of contamination?	Refer to the Response to Comments table in the **Soils and Surface Water** section of this FSA.
	Scenario 3: Question 11.5	What happens to this recycled water if it fails to register as “clean”? How will it be disposed of?	Refer to the Response to Comments table in the **Soils and Surface Water** section of this FSA.
	Scenario 3: Question 11.6	Will the applicant just dilute the recycled water until it registers as “clean”? If so, how much additional water would this require?	Refer to the Response to Comments table in the **Soils and Surface Water** section of this FSA.

	Scenario 3: Question 11.7	If the fluid samples fail to register as "clean" and the applicant dilutes it with additional water until it can register as clean enough for discharge, isn't the same amount of "nonclean" chemicals being discharged into the environment? If so, what is the cumulative affect of this discharge to soil, water and biological resources over the life of the proposed project?	
General Questions: Dust Control Plan for Operations	Question 1	Are there alternative dust control methods for the operational portion of the proposed project that have not been included here? If so, what are they and what are their potential direct, indirect and cumulative impacts?	The project owner would need to submit the dust control plan according to AQ-SC7. California Energy Commission staff would assess the Dust Control Plan for the operational portion of the project once construction is completed. The Energy Commission does not propose or recommend alternative dust control plans. The facility owner would be required to use approved suppressants and methods of application.
	Question 2	Why does Staff believe it is appropriate to exclude these issues, impacts and decisions relevant to the Dust Control Plan for both the construction and operational phase of the proposed project and should only be vetted after the California Energy Commission CEQA equivalency process has closed?	Staff believes we have evaluated the AQ issues and impacts from the project to less than significant with all associated mitigation measures. Siting regulations Section 1742.5 states the staff are to assess the environmental effects of the applicant's proposal and make a recommendation whether this project would or would not cause a CEQA significant impact.
	Question 3	Of the three scenarios outlined above to be used for fugitive and windblown dust control during operations, which of them would rank as the environmentally preferred alternative over the life of the project?	Refer to the Response to Comments table in the **Alternatives** section of this FSA.
12. REQUIRED EARTHMOVEMENT: FINAL GEOTECHNICAL REPORT	Question 12.1	What are the reasons Staff failed to request a Final Geotechnical Report be performed and completed by the applicant during the discovery period for purposes of siting and CEQA analysis?	Refer to the Response to Comments table in the **Paleontological** section of this FSA.
	Question 12.2	How has Staff determined the proposed project site is suitable to support the current design over the life of the project without significantly altering the native soils, landscape and environmental?	Refer to the Response to Comments table in the **Soils and Surface Water** section of this FSA. Please see the **Biology** section for response for "wildlife abundance and distribution"
	Question 12.3	Why does Staff believe it is possible to adequately determine construction and operational impacts, levels of significance and appropriate mitigation measures for the proposed project absent the results of the Final Geotechnical Report with respect to air quality, additional construction emissions, and additional traffic impacts for trucks that will be required to haul in or haul out soil stabilizing agents?	Refer to the Response to Comments table in the **Paleontological** section of this FSA.
13. FINAL GEOTECHNICAL REPORT: COMPLIANCE WITH RULE 502. 3.16	Question 13.1	Since the determinations of the Final Geotechnical Report has yet to be revealed, how can the proposed project's approval comply with the necessity to regulate fugitive and windblown dust as defined by Rule 502.316 regarding earthmovement?	The Final Geotechnical Report is not finalized until just before construction of a project, and is not required in order for California Energy Commission staff to make a recommendation on significance of a project. California Energy Commission staff believes we have enough information in the Preliminary Geotechnical Report to make findings and require adequate mitigation.
	Question 13.2	What is California Energy Commission Staff's definition of "emissions caused by the movement of soil" as defined in Rule 502.3.16 and how does it apply or not apply with respect to potential emissions resulting from the movement, replacement and/or stabilizing of soil as outlined in the applicant's Preliminary Geotechnical Report?	Because this is a district rule, we defer to the districts definition. GBUAPCD Response: District Rule 502 applies to agricultural operation sites (see Section 2.0 of the rule), and the purpose of the rule "is to limit fugitive dust emissions from agricultural operation sites…"(Section 1.0) The rule does not apply to activities or emissions from facilities other than agricultural operation sites.

	Question 13.3	Wouldn't including the findings of the Final Geotechnical Report impact the emissions analysis of the projects emissions compliance as well as insuring appropriate dust mitigation measures that are tailored for the soil types of the area in the Conditions of the Permit versus the current generic "one-size-fits-all" approach that was deemed inadequate for the Owen's Valley mitigation measures?	Staff does not believe it is necessary to have a Final Geotechnical Report or to prepare a more detailed analysis of potential fugitive dust emissions to ensure that appropriate dust mitigation measures are imposed for this project. The District and the California Energy Commission have proposed performance-based mitigation requirements. GBUAPCD Response for inadequacy of the Owens's Valley Mitigation: The District requires more sophisticated monitoring techniques at Owens Lake because Owens Lake has a severe and longstanding PM10 fugitive dust problem that has been the subject of extensive study. Fugitive dust from construction projects are an entirely different and, in many respects, a much simpler class of fugitive dust problem and can be addressed through enforcement of Rule 401 (Fugitive Dust), which is intended to minimize the formation and transport of fugitive dust from anthropogenic activity, and Rule 402 (Nuisance), which is intended to minimize emissions that would cause injury, and through the imposition of the mitigation measures required by PDOC Condition 30.
	Question 13.4	Since the proposed project requires a variety of vehicles and roads in order to operate over its lifetime, why has issuing daily, monthly and annual limits on fugitive dust created by the daily operations of the solar plants so far evaded criteria pollutant emissions limits?	All criteria pollutant emission levels were included in the California Energy Commission staff's Preliminary Staff Assessment and are included the Final Staff Assessment. Please see Air Quality Table 8 for "Operations", and Table 7 for "Construction" for all criteria pollutant emissions. The table includes onroad and offroad construction and operations vehicles, and non construction "worker" vehicles, traveling both onsite and offsite.
	Question 13.5	Will California Energy Commission Staff require PM10/PM2.5 limits for the operational phase of the proposed project just like other criteria air pollutants will be limited by Conditions of the Permit and the GBUAPCD's Permit to Operate?	Both PM10 and PM2.5 are regulated criteria pollutants and the applicants are required to mitigate so that their impacts are less than significant. Yes there are conditions of certification (i.e.. **AQ-SC6**, **AQ-SC7, AQ-10** & **11**) that will limit emissions during both Construction and Operational phases of the project.
14. DUST MITIGATION MEASURES: "NORMAL" VERSUS WORST-CASE SCENARIOS	Question 14.1	What are the wind speeds California Energy Commission Staff defines as "normal" and what are the wind speeds that meet the criteria of "non-normal" that the proposed dust mitigation measures won't cover?	"Normal" wind speeds are those that occur under meteorological conditions typical of the project site. The meteorological data set used in evaluating fugitive dust emissions from the project included wind speeds above 11.1 meters per second (25 mph). There are no wind speeds that the dust mitigation plan won't cover.
	Question 14.2	What mitigation measures, if any, does the CEC Staff propose for dust impacts in "worst-case scenarios" that result from construction and operational activities such as wind events resulting in wind speeds in excess of 25 mph?	Please see **AQ-SC4**, Dust Plume Response Requirements. .
	Question 14.3	What mitigation measures does the CEC Staff recommend to protect public health during the construction and operational phases of the proposed project to insure air quality standards don't exceed significant thresholds of PM10/PM2.5 fugitive and windblown dust emissions for wind speeds occurring in the project area outside the currently undefined definition of "normal"?	Staff imposes conditions of certification that are intended to ensure air quality impacts are reduced to less than significant. Staff has recommended AQ-SC1 to AQ-SC5 during construction and AQ-SC6 to AQ-SC9 during operations. Also refer to the Response to Comments table in the **Public Health** section of this FSA.

	Question 14.4	How will the CEC or the GBUAPCD monitor fugitive and windblown dust levels during the operational portion of the proposed project to detect levels and frequency of PM10/PM2.5 emissions exceeding significant thresholds and posing threats to public health?	Refer to the Response to Comments table in the **Public Health** section of this FSA.
15. VALLEY FEVER	Question 15.1	Which regulatory agencies is CEC Staff referring to that recognize this is an appropriate mitigation measure the public can take to protect themselves from Valley Fever?	Refer to the Response to Comments table in the **Public Health** section of this FSA.
	Question 15.2	Where have these regulatory agencies posted this policy and does it supersede laws aimed at protecting public health from known infections such as those produced by the fungus responsible for inducing Valley Fever?	
	Question 15.3	How will tourists passing through and those visiting the area for recreational purposes protect themselves from air borne fungus resulting from project site disturbances as they have no place to go indoors?	
	Question 15.4	How will customers at the St. Theresa Mission and Front Site Training Institute protect themselves from exposure due to the proposed projects volume of site disturbance during both the construction and operational phase of the proposed project?	
	Question 15.5	What is the feasibility of local residents and others in the area “staying indoors” during times when wind events last for longer than 1 day as is known to occur in the area?	
	Question 15.6	How does the currently proposed mitigation measure of staying indoors during potential exposure times comply with Nuisance Regulation H&SC §41700?	
	Question 15.7	Considering the proposed project site will experience continued soil disturbance over the project’s lifetime due to critically required maintenance activities, is this the only mitigation plan that can be utilized to protect public health for the next 25-30 years if the project is approved?	
16. CONSTRUCTION AND OPERATIONAL DUST: T&E SPECIES	Question 16.1	Are there any studies that have analyzed the impacts of construction emissions, fugitive dust, or chemical dust suppressants in relation to respiratory trends and impacts to Desert Tortoise that the CEC Staff is aware of and might apply to the proposed project?	California Energy Commission staff relies on the federal primary and secondary ambient air quality standards to protect against adverse impacts to humans, animals and plants. Please see the **Biology** section for response regarding Desert Tortoise.
	Question 16.2	What is the projected zone of impact to Desert Tortoise and other special status species from project emissions (construction and operational), fugitive dust and onsite chemical use (such as dust suppressants/soil binders) if the proposed project is approved?	

17. FOOD PRODUCTION/PRODUCE EXPOSURE PATHWAYS	Question 17.1	While it is acknowledged that serpentine habitat containing specialized soils and adaptive plant species related to those soils may be adversely affect from NOx emissions, could the NOx emissions and their cumulative impacts over the life of the project effect the wide variety of fruits and vegetables currently grown in the area for local food production?	GBUAPCD Response: Ambient air quality standards are set at levels that are protective of public health and welfare. CEC and Air District staff are responsible for evaluating the compliance of proposed stationary sources with these ambient air quality standards. The ambient air quality impact assessment submitted for the HHSEGS project demonstrates that project impacts will be below the most stringent state and federal NO2 standards, even when combined with existing background ambient NO2 levels. On this basis, we have concluded that NOx emissions from the proposed project will not result in NO2 concentrations that would cause damage to fruits, vegetables, or other crops or vegetation in the area. Secondary, Federal AAQS are intended to address these effects.
	Question 17.2	Are there species of fruits, vegetables or alternative types of vegetation that may be highly sensitive to nutrient absorption via roots or leaves as described in the "serpentine habitats" that may also be affected by annual or cumulative emissions from the proposed project? If so, what are they and what are the emissions impact levels that could trigger adverse effects?	Energy Commission and Air District staff are not aware of any specific species of fruits, vegetables or alternative types of vegetation that may be highly sensitive to nutrient absorption via roots or leaves. Secondary, Federal AAQS are intended to address these issues. Please see the **Biology** section for response for "vegetative species".
	Question 17.3	As NOx builds within the soils in the area as well as other criteria and non criteria pollutants and PAH's, (i.e., diesel particulate matter, VOC's, etc.), over the life of the project, can these cumulative impacts cause our fruit trees or vegetable gardens from obtaining the nutrients they need to grow and/or produce fruit via the root systems, clog the leaves thereby preventing adequate photosynthesis, or potentially impact flower production that may in turn cause reductions in product yield or plant death?	Oxides of nitrogen (NOx) emissions are comprised of nitric oxide (NO) and nitrogen dioxide (NO2), both of which are gases at standard conditions. These convert to secondary aerosols that eventually deposit on soils, but this occurs at great distances downwind and nitrogen deposition occurs more from automobile traffic. Air Quality Staff if unaware of any such studies. Please see the **Biology** section for response for "Nitrogen Deposition" questions.
	Question 17.4	Are there models for air emissions impacts on species-specific fruit/vegetable production and yield that could tell those in the community that produce food more about the potential direct, indirect and cumulative impacts to our food production over the life of the project?	Nitrogen deposition models could be used, but they are not specific to crop type. No modeling of nitrogen deposition impact is needed because it is not expected to be a problem for HHSEGS, given the expected annual NOx emissions rate. Please see the **Biology** section for response for "Nitrogen Deposition".
	Question 17.5	If agricultural production on a commercial scale were to be initiated surrounding the proposed project site over the life of the project, what impacts will emissions have to those commercial crops?	As stated above by the local air district (see 17.1) secondary National Ambient Air Quality Standards (NAAQS) protect against these effects. The project will not cause or contribute to an exceedance of a NAAQS, so the project is not expected to cause an adverse impact on commercial crops, should they be planted around the facility site.
	Question 17.6	If these models on food production exist, would the CEC Staff recommend the applicant perform a modeling analysis for direct, indirect and cumulative impacts to community food production over the life of the project? If not, why not?	No, nitrogen deposition is not expected to be a problem for HHSEGS. See response to 17.4
	Question 17.7	Are there other sources of air pollution, such as the fugitive dust example given by the Charpied's who claim they lost 30% of their crops through false pollination, which may also adversely impact local food production if the proposed project is approved?	California Energy Commission staff relies on the federal primary and secondary ambient air quality standards to protect against adverse impacts to humans, animals and plants.
	Question 17.8	What does the CEC Staff define as a "significant impact" on food production? 10% loss of crops/vegetation? 20% loss of crops/vegetation? 50% loss of crops/vegetation?	California Energy Commission staff does not assess significant impact on food production and therefore does not use such a threshold.

	Question 17.9	Can single source emissions, cumulative emissions or other impacts from the proposed project reduce local pollinators (insects) to a significant degree that in turn would cause a reduction and/or prevent of pollination of food crops?	California Energy Commission staff does not believe there are any indications of potential concentrations in excess of state or federal ambient air quality standards. Staff does not believe the impacts from the proposed project would be sufficient to cause any loss of crops or vegetation in the area. This is the basis for staff's conclusion that the project will have no significant impact on food production in the area. Also see response to 17.4
18. COMMUNITY HEALTH RISK ASSESSMENT	Question 18.1	What does this chart reflect and model besides cancer risks?	Refer to the Response to Comments table in the **Public Health** section of this FSA.
	Question 18.2	What chemicals (by specific component) and emissions does this chart represent under “Acute Health Hazard Index” and “Chronic Health Hazard Index”?	
	Question 18.3	Does it incorporate just carcinogenic risks exclusively or does it incorporate other health risks such as respiratory conditions? If so, which ones?	
	Question 18.4	Did the applicant model or provide any Health Risk of Diesel Exhaust assessment for potential respiratory impacts or other health impacts to workers or local populations resulting from diesel emissions besides cancer? If not, why not?	
	Question 18.5	Did the CEC Staff request any additional Health Screening Risks of Diesel Exhaust from the applicant besides the supplied cancer risk assessment or consult with the applicant in any way prior to the applicant initiating the parameters for the Health Screening Risk modeling? If not, why not?	
	Question 18.6	Where is the “produce ingestion pathway” referred to in the GBUAPCD’s response or in the AFC files or subsequent documents?	
19. ALL TERRAIN VEHCILES: EVADING ENVIRONMENTAL IMPACT ANALYSIS?	Question 19.1	Is the Great Basin Unified Air Pollution Control District unaware of how the applicant intends to utilize the all-terrain vehicles at the proposed project site?	The GBUAPCD evaluated all traffic associated with construction and operation as did staff. The all-terrain vehicles at the proposed site are not expected to operate excessively on active disturbed surfaces, and therefore would not contribute significantly to onsite fugitive PM10 and PM2.5 emission.
	Question 19.2	How can the soil disturbance of installing 170,000 heliostat/mirror assemblies be considered “negligible”?	GBUAPCD Response: In the construction industry, disturbed area or soil disturbance area typically means an area that is altered as a result of clearing, grading, and/or excavation. Staff use of "negligible" in describing heliostat installation in the field (vehicle driving, vegetation mowing, and foot traffic) reflected that no grading would be required. Staff changed the description to “Area of Land Grading and Excavation” to avoid confusion. Please see Total Soil Disturbance discussion in the Soils & Surface Water section.
	Question 19.3	Where is the site-specific data located that describes how the heliostat/mirror assemblies will be installed, how many will be installed per day per ATV and how long this process is expected take?	The general installation procedure for heliostats is found in the Project Description section. Information about the number of heliostats installed per day is not included, and staff does not need to know that in order to recommend issuance of the license. The applicant may be able to answer this question for the commenter.

15. Traffic and Transportation	Question 15.1	Will CEC Staff provide any mitigation measures, such as requiring waiting trucks to turn off their engines if they must wait longer than three minutes for site entry in order to control air emissions and 5:00 am noise pollution to Charleston View residents located merely 5 acres away from the Old Spanish Trail Highway?	Staff has included in staff condition AQ-SC5(j): All diesel heavy construction equipment shall not idle for more than 5 minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement. Please also see **Traffic and Transportation** and **Noise** technical section regarding time duration of construction related activity.
5	**July 17, 2012**	**Inyo County**	
Inyo County General Plan Goal or Policy	**Identified by PSA as LORS?**	**Consistency clause made by Inyo County**	**Response by Energy Commission Staff**
Goal AQ-1: "Provide good are quality for Inyo County to reduce impacts to human health and the economy."	No	"Compliant. Mitigation has been developed for impacts to air quality that will decrease them to less than significant levels."	Change has been made to the LORS Air Quality Table 1 and in AQ section Compliance with LORS, and is expected to also be consistent with GBUAPCD Rule 400 and 401, 402 and 404.
Policy AQ-1.2/Attainment Programs: "Participate in the GBUAPCD's attainment programs."	No		
Policy AQ-1.3/ Dust Suppression During Construction: "Require dust-suppression measures for grading activities."	No		
Policy AQ-1.5/Monitor Regional Development: "Publicly object to development proposals within the region that do not adequately address and mitigate air quality impacts, especially fugitive dust."	No		
Comment	**DATE**	**COMMENT TOPIC**	
13	**Pre-PSA comment letter posted July 3, 2012**	**Basin & Range Watch**	
	Concern No. 1	"We are worried that industrial construction in the region will compromise the air quality to the point where not only visual resources, but public health will be impacted."	A section has been included in the FSA to address these concerns by the Basin and Range Watch Group. Please see the subtopic "Construction Impacts Mitigation" section of the FSA on page 4.1-25 of the Air Quality section. Also please see **AQ-SC1** through **AQ-SC6** for staff-recommended conditions of certification for construction of the project.
	Concern No. 2	"Construction should not be permitted during days of high winds. Wind speeds of 15 MPH and higher should be determining factors that limit construction. Construction should also be limited during the hottest months of the year. Evaporation rates will be greatest during the months of June, July and August."	